6.3 EMERGENCY CORE COOLING SYSTEMS

6.3.1 Design Bases and Summary Description

Section 6.3.1 provides the design bases for the ECCS and a summary description of the systems as an introduction to the more detailed design descriptions provided in Section 6.3.2 and the performance analysis provided in Section 6.3.3.

6.3.1.1 Design Bases

6.3.1.1.1 Performance and Functional Requirements

The ECCS is designed to provide cooling for postulated LOCAs caused by ruptures in primary system piping. The functional requirements (for example, coolant delivery rates) specified in Table 6.3-1 are such that the system performance under all LOCA conditions postulated in the design satisfies the requirements of 10CFR50.46. These requirements are summarized in Section 6.3.3.2. In addition, the ECCS is designed to meet the following requirements:

1. Protection is provided for any primary system line break up to and including the DER of the largest line.

2. Two independent phenomenological cooling methods (flooding and spraying) are provided to cool the core.

3. One high-pressure cooling system is provided that is capable of maintaining water level above the top of the core and preventing ADS actuation for breaks of lines less than 1 in nominal diameter.

4. No Operator action is required until 10 min after an accident to allow for Operator assessment and decision.

5. The ECCS is designed to satisfy all criteria specified in Section 6.3.

6. A sufficient water source and the necessary piping, pumps, and other hardware are provided so that the containment and reactor core can be flooded for core heat removal following a LOCA.

6.3.1.1.2 Reliability Requirements

The following reliability requirements apply:

1. The ECCS must conform to all licensing requirements and good design practices of isolation, separation, and common mode failure considerations.

2. The ECCS network has sufficient redundancy so that adequate cooling can be provided to meet the

requirement of 10CFR50.46 even in the event of specified failures. The following equipment makes up the ECCS:

a. 1 HPCS.

b. 1 LPCS.

c. 3 LPCI loops.

d. 1 ADS.

3. The ECCS is designed so that a single active or passive component failure, including failure of power buses, electrical and mechanical parts, cabinets, and wiring, does not disable the ADS.

4. In the event of a break in a pipe that is not a part of the ECCS, no single active component failure in the ECCS prevents automatic initiation and successful operation of less than the following combination of ECCS equipment:

   a. 3 LPCI loops, the LPCS, and the ADS (i.e., HPCS failure); or

   b. 2 LPCI loops, the HPCS, and the ADS (i.e., Division I diesel generator failure); or

   c. 1 LPCI loop, the LPCS, the HPCS, and ADS (i.e., Division II diesel generator failure).

5. In the event of a break in a pipe that is a part of the ECCS, no single active component failure in the ECCS prevents automatic initiation and successful operation of less than the following combination of ECCS equipment:

   a. 2 LPCI loops and the ADS; or

   b. 1 LPCI loop, the LPCS, and the ADS; or

   c. 1 LPCI loop, the HPCS, and the ADS; or

   d. The LPCS, the HPCS, and ADS.

   These are the minimum ECCS combinations which result after assuming any failure (from 4 above) and assuming that the ECCS line break disables the affected system.

6. Long-term (10 min after initiation signal) cooling requirements call for the removal of decay heat via the SWP system. In addition to the break that initiated the loss-of-coolant event, the system must be able to

sustain one failure, either active or passive, and still have at least one ECCS pump (LPCI, HPCS, or LPCS) operating with a heat exchanger and 100-percent service water flow.

7. Offsite power is the preferred source of power for the ECCS network and every reasonable precaution is made to assure its high availability. However, onsite emergency power is provided with sufficient redundancy and capacity so that all the above requirements can be met even if offsite power is not available.

8. The onsite diesel fuel reserve is in accordance with ANSI STD N195-1976 criteria.

9. The diesel load configuration is as follows:

    a. 1 LPCI loop (with heat exchanger) and the LPCS connected to a single diesel generator (Division I).

    b. 2 additional LPCI loops (1 loop with heat exchanger) connected to a single diesel generator (Division II).

    c. The HPCS connected to a single diesel generator (Division III).

    All these diesel generators are physically isolated from and electrically independent of each other.

10. Systems that interface with, but are not part of, the ECCS are designed and operated in such a way that failure(s) in the interfacing systems do not propagate to and/or affect the performance of the ECCS.

11. Non-ECCS systems interfacing with the ECCS buses are automatically shed and/or inhibited from the ECCS buses when a LOCA signal exists and offsite ac power is not available.

12. There are three emergency dc buses corresponding to the three divisions of the onsite emergency ac power system. Each dc bus is physically isolated from and electrically independent of any other emergency dc bus. Each dc bus is fed by its own battery and battery charger.

13. Each system of the ECCS, including flow rate and sensing networks, is capable of being tested during shutdown. All active components are capable of being tested during plant operation (except the valves identified in Sections 6.3.2.2.1, 6.3.2.2.3, and 6.3.2.2.4, which are tested only during reactor

shutdown), including logic required to automatically initiate component action.

14. Provisions for testing the ECCS network components (electronic, mechanical, hydraulic, and pneumatic, as applicable) are installed in such a manner that they are an integral and nonseparable part of the design.

15. The revised NPSH guidance contained in SECY 11-0014 will be applied for all ECCS pumps following an EPU.

6.3.1.1.3 ECCS Requirements for Protection from Physical Damage

The ECCS piping and components are protected against damage from movement, from thermal stresses, from the effects of the LOCA, and the SSE. The ECCS is protected against the effects of pipe whip and jet impingement, which might result from piping failures up to and including the design basis event LOCA. This protection is provided by separation, pipe whip restraints, or other energy-absorbing materials if required. One or more of these three methods is applied to provide protection against damage to piping and components of the ECCS which otherwise could result in a reduction of ECCS effectiveness to an unacceptable level.

Mechanical separation outside the drywell is achieved as follows:

1. The ECCS is separated into three functional groups:

    a. HPCS.

    b. LPCS plus 1 LPCI plus 100-percent service water and heat exchanger.

    c. 2 LPCI pumps plus 100-percent service water and heat exchanger.

2. The equipment in each group is separated from that in the other two groups. In addition, the HPCS and RCIC system (which is not part of the ECCS) are physically separated.

3. Separation barriers are constructed between the functional groups as required to assure that environmental disturbances such as fire, pipe rupture, and falling objects affecting one functional group do not affect the remaining groups. In addition, separation barriers are provided as required to assure that such disturbances do not affect both the RCIC and the HPCS.

6.3.1.1.4 ECCS Environmental Design Basis

Each ECCS and the RCIC system has a safety-related injection/isolation testable (ECCS only) check valve located in piping within the drywell. In addition, the RCIC system has an isolation valve in the drywell portion of its steam supply piping. No portion of the ECCS and RCIC piping is subject to drywell flooding since water drains into the suppression chamber through the downcomers. ECCS and RCIC equipment is qualified for the environmental conditions in which they must operate, as discussed in Section 3.11.1.

After a large-break LOCA, maintenance cannot be performed in the secondary containment until the high levels of radioactivity have been reduced. For post-LOCA long-term cooling, only one core spray pump is required to maintain water level in the core. Similarly, only one RHR pump, heat exchanger, and service water pump are required to remove heat from the core or suppression pool. During this time, redundant systems that are available to perform the long-term cooling function make maintenance unnecessary. Remote maintenance is not feasible.

Once the radioactivity levels have been reduced, limited maintenance on essential equipment could be performed in the secondary containment. All ECCS lines may be isolated and drained for maintenance on pump seals and valve packings. The RHR system heat exchangers may be drained for servicing separately from the rest of the system. Use of the redundant low pressure systems, located on the opposite side of the secondary containment to maintain core water level and suppression pool or core temperature, permits isolation of a loop requiring service and performance of the necessary maintenance.

Localized radioactive buildup in areas requiring maintenance is reduced by the reactor building ventilation system which recirculates and mixes the secondary containment atmosphere.

6.3.1.2 Summary Descriptions of ECCS

The ECCS injection network consists of the HPCS system, the LPCS system, and the LPCI mode of the RHR system. These systems are briefly described here as an introduction to the more detailed system design descriptions provided in Section 6.3.2. The ADS which assists the injection network under certain conditions is also briefly described. A comparison of the ECCS designs of other BWRs is provided in Table 1.3-2.

6.3.1.2.1 High-Pressure Core Spray

The HPCS pumps water through a peripheral ring spray sparger mounted above the reactor core. Coolant is supplied over the entire range of system operating pressures. The primary purpose of HPCS is to maintain reactor vessel coolant inventory after small breaks which do not depressurize the reactor vessel. HPCS also provides spray cooling heat transfer during breaks in which core uncovery is calculated.

6.3.1.2.2 Low-Pressure Core Spray

The LPCS is an independent loop similar to the HPCS. The primary difference is that the LPCS delivers water over the core at relatively low reactor pressure. The primary purpose of the LPCS is to provide coolant inventory makeup and spray cooling during large breaks in which the core is calculated to uncover. Also, following a small break and ADS initiation, LPCS provides coolant inventory makeup.

6.3.1.2.3 Low-Pressure Coolant Injection

LPCI is an operating mode of the RHR system. Three pumps deliver water from the suppression pool to the bypass region inside the shroud, through three separate reactor vessel penetrations, to provide inventory makeup following large pipe breaks. Following a small break and ADS initiation, LPCI provides coolant inventory makeup.

6.3.1.2.4 Automatic Depressurization System

The ADS utilizes 7 of the 18 SRVs to reduce reactor pressure following small breaks in the event of HPCS failure. When vessel pressure is reduced to within the capacity of the low-pressure systems (LPCS and LPCI), these systems provide inventory makeup to maintain acceptable post-accident temperatures.

6.3.2 System Design

A detailed description of the individual systems, including individual design characteristics of the systems, is provided in Sections 6.3.2.2.1 through 6.3.2.2.4. The following discussion provides details of the combined systems, in particular, those design features and characteristics which are common to all systems.

6.3.2.1 Schematic Piping and Instrumentation Diagrams

The P&IDs for the ECCS are identified in Section 6.3.2.2. The process diagrams that identify the various operating modes of each system are also identified in Section 6.3.2.2.

6.3.2.2 Equipment and Component Descriptions

The initiating signal for the ECCS comes from at least two independent and redundant sensors of drywell pressure and reactor water level. The ECCS is automatically actuated and requires no Operator action during the first 10 min following the accident. A time sequence for starting of the systems is provided in Table 6.3-2.

Normally, electric power for operation of the ECCS is received from offsite ac power sources. Upon LOOP, operation is from onsite standby diesel generators. The diesel generators have sufficient independence, redundancy, and capacity that all ECCS requirements are satisfied. There are three independent divisions of the onsite emergency ac power system: Divisions I, II, and III. Each Division has its own diesel generator. The HPCS is powered from an independent ac supply bus (Division III). The LPCS and one LPCI are powered from a second (Division I) ac supply bus and the two remaining LPCIs are powered from a third and separate ac supply bus (Division II). The HPCS has its own diesel generator as its alternate power supply. The LPCS and one LPCI loop switch to the Division I diesel generator supply and the other two LPCI loops switch to the Division II diesel generator power supply. Section 8.3 contains a more detailed description of the onsite emergency ac power system.

The ECCS pumps' NPSH was reevaluated for Extended Power Uprate (EPU) in response to an NRC Request for Additional Information (RAI) related to the EPU License Amendment Request (LAR). The NPSH evaluation did not take credit for containment accident pressure. The acceptance criteria for the evaluation were as follows:

1. The available NPSH (NPSHA) is greater than the required NPSH ($NPSHR_{3\%}$), including 21% margin ($NPSHR_{eff}$) for all cases.

2. The margin ratio defined by NPSHA/$NPSHR_{3\%}$ is greater than 1.6 for all cases. If not, establish that the amount of time operating at a margin ratio less than 1.6 is less than 100 hours.

3. The margin ratio defined by NPSHA/$NPSHR_{3\%}$ plus 21% margin (i.e., $NPSH_{eff}$) is greater than 1.6 for all cases. If not, establish that the amount of time operating at a margin ratio less than 1.6 is less than 100 hours.

The evaluation utilized the following considerations:

1. These scenarios were considered:

   a. Design Basis Accident – Loss of Coolant Accident (DBA-LOCA)

   b. Alternate Shutdown Cooling (ASDC)

   c. Appendix R Fire

   d. Anticipated Transient without Scram (ATWS)

   e. Station Blackout (SBO)

2. The $NPSHR_{3\%}$ values at runout conditions were extracted from the calculations of record for the types of pumps

involved. The values used were those that represent the NPSH read directly from the vendor pump curves at the appropriate flow value.

3. The differential pressure (DP) for the strainers was applied only to the DBA-LOCA NPSH evaluation. Other non-DBA events used the calculated clean DP.

4. The evaluation is performed at the maximum temperature reached in the particular analysis that is being evaluated: for example, the DBA-LOCA analysis[7] in the EPU LAR indicates the maximum suppression pool temperature is 207°F.

5. All cases are evaluated based on a 14.696 psia pressure at the suppression pool surface. No credit is taken for containment accident pressure.

6. Strainer head loss was based on established debris loads, and determined by large-scale testing performed by CDI. The CDI test results determined a maximum strainer head loss of 85.3 inches of water (7.11 feet) at a temperature of 208°F. Adjustments to head loss were made based on variations in viscosity at specific temperature being considered.

The evaluation of the NPSH generated the following results:

1. The NPSHA is greater than $NPSH_{eff}$ for all cases.

2. The NPSH margin ratios are above 1.6 for all pumps for liquid temperatures at or below 197.7°F with a strainer loss of 7.57 ft.

3. At a liquid temperature of 207°F and a strainer loss of 7.15 ft, the NPSH margin ratios are below 1.6 for the LPCI pumps for the $NPSHR_{3\%}$ value, and for both the LPCS and LPCI pumps for the $NPSH_{eff}$ values.

4. The LPCI pumps, which are limiting compared to LPCS and HPCS, will operate above 197.7°F (a margin ratio less than 1.6 for $NPSH_{eff}$) for approximately 23 hours[7] with a strainer loss of 7.57 ft. For the $NPSHR_{3\%}$ margin ratio, the time below a margin ratio of 1.6 would be substantially shorter.

Based on the results, the acceptance criteria area satisfied for all pumps for all cases.

<u>HPCS</u>

The HPCS pump can take suction from the CST or the suppression pool. However, the combination of minimum static head, maximum fluid vapor pressure, and frictional losses in piping and fittings make suction from the suppression pool the limiting condition of NPSH available.

Calculated values for NPSH minimum and NPSH available for the HPCS pump are:

$NPSH_{min}$ = 10.48 ft

$NPSH_{avail}$ = 5.18 ft

<u>LPCS</u>

The LPCS pump takes suction from either the suppression pool or the RHR system. However, suction from the RHR system is used only during shutdown for test purposes and does not constitute the limiting condition for NPSH available. The combination of minimum static head, maximum fluid vapor pressure, and frictional losses in piping and fittings make suction from the suppression pool the limiting condition of NPSH available.

Calculated values for NPSH minimum and NPSH available for the LPCS pump are:

$NPSH_{min}$ = 7.69 ft

$NPSH_{avail}$ = 0.19 ft

<u>LPCI</u>

This ECCS mode of RHR system operation constitutes the limiting condition of NPSH available for the RHR pumps. With all other conditions equal, the NPSH available for RHR pump B is the least of the three due to the greatest frictional losses in suction piping and fittings. The ECCS mode of operation is the worst case based upon the fluid vapor pressure.

Calculated values of NPSH minimum and NPSH available for RHR pump B while performing its ECCS function are:

$NPSH_{min}$ = 11.87 ft

$NPSH_{avail}$ = 0.37 ft

The submergence depth of ECCS suction lines in the suppression pool is adequate to prevent vortex formation from adversely affecting ECCS pump performance. Submergence depth is based on calculations which include the requirements of NUREG-0869 (draft issued for comments dated April 1983). For the LPCI pumps, the elevation at the top of the suction strainer inlet (189 ft 8 in) is 8 ft below the minimum drawdown water level (el 197 ft 8 in). For HPCS and LPCS pumps, these submergence depths are 8 and 9.5 ft, respectively.

Post-EPU NPSH Evaluation

The NPSH available values for the ECCS pumps were evaluated for the maximum calculated temperature for DBA LOCA for compliance with the following acceptance criteria of SECY 11-0014:

1. $NPSHA > NPSHR_{eff}$ for all cases

2. $NPSHA/NPSHR_{3\%} > 1.6$ for all cases (for cases less than 1.6, operating time is limited to < 100 hr)

3. $NPSHA/NPSHR_{eff} > 1.6$ for all cases (for cases less than 1.6, operating time is limited to < 100 hr)

where NPSHA is NPSH Available, $NPSHR_{3\%}$ is NPSH that results in a 3-percent drop in pump discharge head, and $NPSHR_{eff}$ is 1.21 times $NPSHR_{3\%}$. The 1.21 factor is utilized to address uncertainties in $NPSH_{3\%}$.

The NPSHA values for the ECCS pumps were evaluated for the DBA LOCA, alternate shutdown cooling, Appendix R, and ATWS maximum calculated temperature without crediting containment accident pressure. All ECCS pumps met Criteria 1 and 2. HPCS and LPCS pumps met Criterion 3, while LPCI pump $NPSHA/NPSHR_{eff}$ ratio was less than 1.6 for DBA LOCA and alternate shutdown cooling. Further evaluation was performed for the operating times with less than 1.6 ratio and confirmed that the operating times are well below the 100 hr limit utilizing the calculated pool temperature transients.

6.3.2.2.1 High-Pressure Core Spray System

The system is designed to pump water into the reactor vessel over a wide range of pressures. For small breaks that do not result in rapid reactor depressurization, the system maintains reactor water level and reduced vessel pressure. For large breaks the HPCS system cools the core by a spray.

The HPCS system consists of a single motor-driven centrifugal pump located outside the primary containment, an independent spray sparger in the reactor vessel located above the core (separate from the LPCS sparger), and associated system piping, valves, controls, and instrumentation. The system is designed to operate from offsite power or from the Division III diesel generator supply if offsite power is not available. The P&ID (Figure 6.3-6 for the HPCS) shows the system components and their arrangement. The HPCS system process diagram (Figure 6.3-1) shows the design operating modes of the system. The flow values were used for original pipe and component sizing and do not represent design basis flow requirements. A simplified system flow diagram showing system injection into the reactor vessel is included on Figure 6.3-1.

The principal active HPCS equipment is located outside the primary containment. Suction piping is provided from the CST and the suppression pool. Such an arrangement provides the capability to use reactor grade water from the CST when the HPCS system functions to back up the RCIC system. The RCIC system is discussed in Section 5.4.6. In the event that the condensate storage water supply becomes exhausted or is not available, automatic switchover to the suppression pool water source assures a closed cooling water supply for continuous operation of the HPCS system. HPCS pump suction is also automatically transferred to the suppression pool if the suppression pool water level exceeds a prescribed value. One of two CSTs reserves water for use by the HPCS with the other CST reserved for RCIC use.

After the HPCS injection piping enters the vessel, it divides and enters the shroud at two points near the top of the shroud. A semicircular sparger is attached to each outlet. Nozzles are spaced around the spargers to spray the water radially over the core and into the fuel assemblies.

The HPCS discharge line to the reactor is provided with two isolation valves. One of these valves is a manual testable check valve located inside the drywell as close as practical to the reactor vessel. HPCS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during LOCA). If the HPCS line should break outside the containment, the check valve in the line inside the drywell prevents the loss of reactor coolant outside the containment. The other isolation valve (which is also referred to as the HPCS injection valve) is a motor-operated gate valve located outside the primary containment as close as practical to HPCS discharge line penetration into the containment. This valve is capable of opening against the maximum differential pressure across the valve for any system operating mode including HPCS pump shutoff head. The valve opens following receipt of a signal to open in order to support the LOCA analysis which assumes that full HPCS flow is available as discussed in the system performance which follows. This valve is normally closed to back up the inside testable check valve for containment integrity purposes. A drain line is provided between the two valves. The test connection line is normally closed with two valves to assure containment integrity.

Controls for the motor-operated components and associated diesel generator are provided in the main control room. The controls and instrumentation of the HPCS system are discussed in Chapter 7.

If a LOCA should occur, a low-low water level signal or high drywell pressure signal initiates the HPCS and its support equipment. The system can also be placed in operation manually.

The HPCS system is capable of delivering rated flow into the reactor vessel within 27 sec of reaching the above-listed conditions. This time includes the emergency diesel generator startup (10 sec), loading, HPCS startup, and injection valve opening. The LOCA analysis assumes that full HPCS flow is available 53 sec after the receipt of an automatic initiation signal.

The HPCS injection automatically stops when a high water level in the reactor vessel signals the injection valve to close. The pump continues to run on minimum flow. The injection valve automatically opens again when a low water level is signaled. The HPCS system also serves as a backup to the RCIC system, in the event the reactor becomes isolated from the main condenser during operation and feedwater flow is lost.

The HPCS pump head flow characteristics used in LOCA analyses are shown in Table 6.3-1. When the system is started, the initial flow rate is established by primary system pressure. As vessel pressure decreases, flow increases. When vessel pressure reaches 100-psi differential pressure between the reactor vessel and the suction source, the system reaches rated core spray flow. The HPCS motor size is based on peak horsepower requirements.

The floor elevation of the HPCS pump (el 175 ft) is sufficiently below the water level of both the CST and the suppression pool to provide a flooded pump suction.

The maximum trip switchover elevation is approximately el 268 ft 2 in. The HPCS pump suction nozzle is located at el 177 ft 11 in.

A MOV is provided in the suction line from the suppression pool. The valve is located as close to the suppression pool penetration as practical. This valve is used to isolate the suppression pool water source when HPCS system suction is from the condensate storage system, and to isolate the system from the suppression pool in the event a leak develops in the HPCS system. The HPCS pump characteristics of head, flow, horsepower, and required NPSH are shown on Figure 6.3-3B.

The design pressure and temperature of the system components are established based on the ASME Section III Boiler and Pressure Vessel Code. The design pressures and temperatures at various points in the system can be obtained from the information on the HPCS process diagram (Figure 6.3-1).

A check valve and flow element are provided in the HPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system (Section 6.3.2.2.5). The flow element is provided to measure system flow rate during LOCA and test conditions, and for automatic control of the minimum low flow bypass gate valve. The measured flow is indicated in the main control room.

A low flow bypass line with a motor-operated gate valve connects to the HPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage due to overheating when other discharge line valves are closed. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

To assure continuous core cooling, signals to isolate the containment do not operate any HPCS valves.

The HPCS system incorporates relief valves to protect the components and piping from overpressure conditions. One relief valve, set to relieve at 1,575 psig, is located on the discharge side of the pump downstream of the check valve to relieve thermally-expanded fluid. A second relief valve is located on the suction side of the pump and is set to relieve at 100 psig with a capacity of >10 gpm at 10-percent accumulation. This valve relieves any high pressure buildup due to leakage past the injection valves from the reactor.

The HPCS components and piping are positioned to avoid damage from the physical effects of DBAs, such as pipe whip, missiles, and high temperature, pressure, and humidity.

The HPCS equipment and support structures are designed in accordance with Category I criteria (Chapter 3). The system is assumed to be filled with water for seismic analysis.

Provisions are included in the HPCS system which permit the HPCS system to be tested. These provisions are:

1. All active HPCS components are testable during normal plant operation except valve 2CSH*V108, which is tested during reactor shutdown.

2. A full flow test line is provided to route water from and to the CST without entering the reactor pressure vessel (RPV). The suction line from the CST also provides reactor grade water to fully test the HPCS including injection into the RPV during shutdown.

3. A full flow test line is provided to route water from and to the suppression pool without entering the RPV.

4. Instrumentation is provided to indicate system performance during normal test operations.

5. All MOVs are capable of remote manual operation for test purposes.

6. System relief valves are removable for benchtesting during plant shutdown.

6.3.2.2.2 Automatic Depressurization System

If the RCIC and HPCS cannot maintain the reactor water level, the ADS, which is independent of any other ECCS, reduces the reactor pressure so that flow from LPCI and LPCS enters the reactor vessel in time to cool the core and limit fuel cladding temperature.

The ADS employs seven nuclear steam system pressure relief valves to relieve high-pressure steam to the suppression pool. Evaluation of one ADS valve out of service is included in this section. Evaluations of a second ADS valve out of service is presented in Appendix 15C. The design, location, description, operational characteristics, and evaluation of the pressure relief valves are discussed in Section 5.2.2. The instrumentation and controls for the ADS are discussed in Section 7.3.1.

6.3.2.2.3 Low-Pressure Core Spray System

The LPCS is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCS operates in conjunction with the ADS, then the effective core cooling capability of the LPCS is extended to all break sizes because the ADS rapidly reduces the reactor vessel pressure to the LPCS operating range. The system head flow characteristic assumed for LOCA analyses is shown in Table 6.3-1.

The LPCS consists of: a centrifugal pump that is powered by normal auxiliary power or the Division I emergency diesel generator; a spray sparger in the reactor vessel above the core (separate from the HPCS sparger); piping and valves to convey water from the suppression pool to the sparger; and associated controls and instrumentation. Figure 6.3-7a, the LPCS system P&ID, presents the system components and their arrangement. The LPCS system process diagram (Figure 6.3-2) shows the design operating modes of the system. The flow values were used for original pipe and component sizing and do not represent design basis flow requirements. Figure 6.3-2 includes a simplified system flow diagram showing injection into the reactor vessel by the LPCS system. The LPCS pump characteristics of head, flow, horsepower, and required NPSH are shown on Figure 6.3-4b.

When low water level in the reactor vessel or high pressure in the drywell is sensed, and with reactor vessel pressure low enough, the LPCS system automatically starts and sprays water into the top of the fuel assemblies to cool the core. The LPCS injection piping enters the vessel, divides and enters the core shroud at two points near the top of the shroud. A semicircular sparger is attached to each outlet. Nozzles are spaced around the sparger to spray the water radially over the core and into the fuel assemblies.

The LPCS pump and all MOVs can be operated individually by manual switches located in the main control room. Operating indication is provided in the main control room by a flowmeter and valve indicator lights. To assure continuity of core cooling, signals to isolate the containment do not operate any LPCS system valves.

The LPCS discharge line to the reactor has two isolation valves. One of these valves is a manual testable check valve located inside the drywell as close as practical to the reactor vessel. LPCS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during LOCA). If the LPCS line should break outside the containment, the check valve in the line inside the drywell prevents loss of reactor water outside the containment.

The other isolation valve (which is also referred to as the LPCS injection valve) is a motor-operated gate valve located outside the primary containment as close as practical to LPCS discharge line penetration into the containment. Signals for opening are based on the differential pressure across the valve. This valve is capable of opening against the maximum expected differential pressure across the valve for any system operating mode. The valve is capable of opening against a differential pressure equal to normal reactor pressure minus the minimum LPCS system shutoff pressure. The valve installation is modified to prevent bonnet pressure locking. The valve is capable of opening following a maximum recirculation line break accident. This valve is normally closed to back up the inside testable check valve for containment integrity purposes. A drain line is provided between the two valves. The test connection line is normally closed with two valves to assure containment integrity.

The LPCS system components and piping are arranged to avoid unacceptable damage from the physical effects of DBAs, such as pipe whip, missiles, and high temperature, pressure, and humidity. All principal active LPCS equipment is located outside the primary containment except for the injection line testable check valve.

A check valve, flow element, and restricting orifice are provided in the LPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system (Section 6.3.2.2.5). The flow element is provided to measure system flow rate during LOCA and test conditions and for automatic control of the minimum low flow bypass gate valve. The measured flow is indicated in the main control room. The restricting orifice is sized during the preoperation test of the system to limit system flow to acceptable values as described on the LPCS system process diagram.

A low flow bypass line with a motor-operated gate valve connects to the LPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage due to overheating when other discharge line valves are closed or reactor pressure is greater than the LPCS system discharge pressure following system initiation. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

LPCS flow passes through a motor-operated pump suction valve that is normally open. This valve can be closed by a remote manual switch (located in the main control room) to isolate the LPCS system from the suppression pool should a leak develop in the system. This valve is located in the LPCS pump suction line as close to the suppression pool as practical. Because the LPCS conveys water from the suppression pool, a closed loop is established for reactor water makeup.

The design pressure and temperature of the system components are established based on the ASME Section III Boiler and Pressure Vessel Code. The design pressures and temperatures at various points in the system can be obtained from the miscellaneous information blocks on the LPCS process diagram (Figure 6.3-2).

The high-pressure portion of the LPCS pump discharge line, which extends from the injection valve (F005) up to the RPV, is designed to withstand reactor pressure. The low-pressure portion of the discharge line is designed to withstand the maximum discharge pressure of the pump at shutoff conditions. Following a signal for LPCS initiation, valve F005 will open once the ΔP across it is less than or equal to 88 psi. However, injection will not begin until the pressure on the downstream side of F006 is below the pump discharge head at bypass flow (approximately 500 psig). The low-pressure portion of the LPCS is further protected from overpressure by relief valve F018 (see Figure 6.3-2).

The LPCS pump is located in the reactor building sufficiently below the water level in the suppression pool to assure a flooded pump suction. A pressure gauge is provided to indicate the suction.

The LPCS system incorporates relief valves to prevent the components and piping from overpressure conditions. One relief valve, located on the pump discharge, is set to protect 550-psig piping with capacity of 100 gpm at 10-percent accumulation. The second relief valve is located on the suction side of the pump and is set to protect 60-psig piping at a capacity of >10 gpm at 10-percent accumulation.

The LPCS system piping and support structures are designed in accordance with Category I criteria (Chapter 3). The system is assumed to be filled with water for seismic analysis.

The following provisions that permit the LPCS system to be tested are included in the LPCS system:

1. All active LPCS components are testable during normal plant operation except valve 2CSL*V101, which is tested during reactor shutdown.

2. A full flow test line is provided to route water from and to the suppression pool without entering the RPV.

3. A suction test line supplying reactor grade water is provided to test pump discharge into the RPV during plant shutdown.

4. Instrumentation is provided to indicate system performance during normal and test operations.

5. All MOVs and air-operated check valves are capable of operation for test purposes.

6. Relief valves are removable for benchtesting during plant shutdown.

6.3.2.2.4 Low-Pressure Coolant Injection

The LPCI, like the LPCS system, is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCI operates in conjunction with the ADS, the effective core cooling capability of the LPCI is extended to all break sizes because the ADS rapidly reduces the reactor vessel pressure to the LPCI operating range.

The head flow characteristics assumed in the LOCA analyses for the LPCI pumps are shown in Table 6.3-1.

Figure 5.4-14 shows a process diagram and process data for the RHR system, including the LPCI. The flow values were used for original pipe and component sizing and do not represent design basis flow requirements. The LPCI pumphead flow characteristics of head, flow, horsepower, and required NPSH are shown on Figure 6.3-5b.

The LPCI subsystem is an operating mode of the RHR system. The LPCI system is automatically actuated by low water level in the reactor or high pressure in the drywell, and uses the three RHR motor-driven pumps to draw suction from the suppression pool and inject cooling water into the reactor core, and accomplish cooling of the core by flooding. Each loop has its own suction and discharge piping and separate vessel nozzle which connects with the core shroud to deliver flooding water on top of the core. In this mode, the RHR system is a high-volume, core-flooding system.

The pump, piping, controls, and instrumentation of the LPCI loops are separated and protected so that any single physical event, or missiles generated by rupture of any pipe in any system within the drywell, cannot make all loops inoperable.

To assure continuity of core cooling, signals to isolate the primary containment do not operate any RHR system valves that interfere with the LPCI mode of operation.

Each LPCI discharge line to the reactor has two isolation valves. The valve inside the drywell is a manual testable check valve, and the valve outside the drywell is a motor-operated gate valve. No power is required to operate the check valve inside the drywell; rather, it opens as a result of LPCI injection flow. If a break were to occur outside of the check valve, it would close to isolate the reactor from the line break.

The MOV outside of the drywell is called the LPCI injection valve and is located as close as practical to the drywell penetration. It is capable of opening against the maximum differential pressure expected for the LPCI mode. The valve is equipped with a pressure differential switch that permits valve opening below a predetermined pressure setting, thus protecting the components and piping upstream of the valves from excessive pressure.

The RHR-LPCI mode is assumed to deliver full flow into the vessel within 66.3 sec following an accident signal, including time to start and load the emergency diesel generators, start the LPCI pumps, and open the LPCI injection valve.

The process diagram (Figure 5.4-14) and the P&ID (Figure 5.4-13) indicate a great many flow paths are available other than the LPCI injection line. However, the low water level or high drywell pressure signals which automatically initiate the LPCI mode are also used to isolate all other modes of operation and revert other system valves to the LPCI lineup except when the system is operating in the shutdown cooling mode. Inlet and outlet valves from the heat exchangers receive no automatic signals as the system is designed to provide rated flow to the vessel whether they are open or not.

A check valve in the pump discharge line is used together with a discharge line fill system (Section 6.3.2.2.5) to prevent water hammer resulting from pump start against a potential shutoff condition. A flow element in the pump discharge line is used to provide a measure of system flow and to originate automatic signals for control of the pump minimum flow valve. The minimum flow valve permits a small flow to the suppression pool in the event that either no discharge valve is open, or in the case of a LOCA, vessel pressure is higher than the pump shutoff head.

Using the suppression pool as the source of water for LPCI establishes a closed loop for recirculation for reactor water makeup.

The design pressures and temperatures, at various points in the system, during each of the several modes of operation of the RHR subsystems, can be obtained from the LPCI process diagram (Figure 5.4-14).

LPCI pumps and equipment are described in detail in Section 5.4.7, which also describes the other functions served by the same pumps if not needed for the LPCI function. The heat exchangers are discussed in Section 6.2.2. The portions of the RHR required for accident protection, including support structures, are designed in accordance with Category I criteria (Chapter 3). The LPCI pump characteristics are shown on Figure 6.3-5b.

The LPCI system incorporates a relief valve on each of the pump discharge lines that protects the components and piping from inadvertent overpressure conditions. These valves are set to relieve pressure at 500 psig. Section 5.2.2 discusses relief valve settings and capacities.

The following provisions are included in the LPCI system to permit testing of the system:

1. All active LPCI components are designed to be testable during normal plant operation (except valves 2RHS*V16A/16B/16C and 2RHS*V39A/39B, which are tested during reactor shutdown).

2. A discharge test line is provided for the three pumps to route suppression pool water back to the suppression pool without entering the RPV.

3. A suction test line supplying reactor grade water is provided to the test loop to discharge into the RPV during plant shutdown.

4. Instrumentation is provided to indicate system performance during normal and test operations.

5. All MOVs and AOVs are capable of manual operation for test purposes.

6. All relief valves are removable for benchtesting during plant shutdown.

6.3.2.2.5 ECCS Discharge Line Fill System

A requirement of the ECCS is that cooling water flow to the reactor vessel be initiated rapidly when the system is called on to perform its function. This quick-start system characteristic is provided by quick-opening valves, quick-start pumps, and the emergency ac power sources. The lag between the signal to start the pump and the initiation of flow into the RPV can be minimized by keeping the ECCS pump discharge lines full. Additionally, if these lines were empty when the systems were called for, large momentum forces associated with accelerating fluid into a dry pipe could cause physical damage to the piping. Therefore, the ECCS discharge line fill system is designed to maintain the pump discharge lines in a filled condition.

On January 11, 2008, the NRC issued Generic Letter 2008-001, Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (Reference 8). Generic Letter 2008-001 requested licensees to evaluate the licensing basis, design, testing, and corrective action programs for the Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems to ensure that gas accumulation is maintained less than the amount that challenges operability of these systems, and that appropriate action is taken when conditions adverse to quality occur at the station:

1. Evaluations have been performed that identified locations in piping systems that are potentially susceptible to gas accumulation,
2. Inspections have been performed, where possible, to substantiate the existence of accumulated gas and quantify volume,
3. Evaluations have been performed to determine if it is possible to eliminate gas from accumulating, and where possible, the associated actions have been implemented (i.e. procedure changes, physical changes),
4. Evaluations have been performed to demonstrate the acceptability of gas pockets that cannot be eliminated, and
5. A program for periodic gas monitoring has been developed

The ECCS piping systems have the potential to develop voids and pockets of entrained gases. The Reactor Core Isolation Cooling (RCIC) system does not fall within the scope of GL 2008-01. However, it has been included within the scope of the NMP2 gas accumulation management program. Maintaining the pump suction and discharge piping sufficiently full of water is necessary to ensure that the system(s) will perform properly and will inject the flow assumed in the safety analyses into the Reactor Coolant System or containment upon demand. This will also prevent damage from pump cavitation or water hammer, and pumping of unacceptable quantities of non-condensable gases (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an ECCS start signal or during shutdown cooling. Piping locations that cannot be fully vented due to the physical layout or inability to dynamically vent will be evaluated on a case by case basis.

Since the ECCS discharge lines are elevated above the suppression pool, check or stop-check valves are provided near the pumps to prevent backflow from emptying the lines into the suppression pool. Past experience has shown that these valves could leak slightly, producing a small backflow that eventually empties the discharge piping. To ensure that this leakage from the discharge lines is replaced and the lines are always kept filled, a water-leg pump is provided for each of the three ECCS divisions. The power supply to these pumps is classified as essential when the main ECCS pumps are deactivated. For the HPCS system when the water-leg pump is inoperative, the system discharge piping can be maintained full by ensuring alignment of the system to the CST with a sufficient static head in the CST to keep the HPCS system full. Indication is provided in the main control room as to whether these pumps are operating, and alarms indicate low discharge line pressure.

6.3.2.3 Applicable Codes and Classifications

The applicable codes and classification of the ECCS are specified in Section 3.2. All piping systems and components (pumps, valves, etc.) for the ECCS comply with applicable codes, addenda, code cases, and errata in effect at the time the equipment is procured. The piping and components of each system of the ECCS within the containment and out to and including the pressure-retaining injection valve are Safety Class 1. The remaining piping and components are Safety Class 2, 3, or noncode as indicated in Section 3.2, and as indicated on the individual system P&IDs. The equipment and piping of the ECCS are designed to the requirements of Category I. This seismic designation applies to all structures and equipment essential to the core cooling function. IEEE codes applicable to the controls and power supplies are specified in Section 7.1.

6.3.2.4 Materials Specifications and Compatibility

Materials specifications and compatibility for the ECCS are presented in Sections 6.1 and 3.2. Nonmetallic materials such as lubricants, seals, packings, paints and primers, and insulation, as well as metallic materials, are selected as a result of an engineering review and evaluation for compatibility with other materials in the system and the surroundings with concern for chemical, radiolytic, mechanical, and nuclear effects. Materials used are reviewed and evaluated with regard to radiolytic and pyrolytic decomposition and attendant effects on safe operation of the ECCS.

6.3.2.5 System Reliability

A system level, qualitative-type plant failure modes and effects analysis (FMEA) of the ECCS is provided in Appendix 15A, Plant Nuclear Safety Operational Analysis (NSOA).

Originally, the FMEA of the balance-of-plant (BOP) instrumentation and control components of the ECCS (HPCS, LPCS, and LPCI) was contained in the Unit 2 FMEA document, which is historical. FMEAs for plant systems are now performed and controlled by the design process.

A single-failure analysis shows that no single failure prevents the starting of the ECCS when required, or the delivery of coolant to the reactor vessel. No individual system of the ECCS is single-failure proof with the exception of the ADS; hence it is possible that single failures may disable individual subsystems of the ECCS. The consequences of the most severe single failures are shown in Table 6.3-3. The most severe effects of single failures with respect to loss of equipment occur if the LOCA occurs in combination with an ECCS pipe break coincident with a LOOP.

For protection against and mitigation of passive ECCS failures, a Class 1E-level instrument is mounted just above floor level in each ECCS pump room to detect passive failures during long-term cooling, assuming failure of other non-Class 1E leak detection equipment located in the floor sump pits. See Section 3.4 for further information.

The following systems interface with, but are not part of, the HPCS system:

1. Reactor core isolation
2. Reactor plant sampling
3. Condensate makeup and drawoff
4. Nuclear boiler system instrumentation
5. Residual heat removal

The following systems interface with, but are not part of, the LPCS system:

1. Condensate makeup and drawoff
2. Residual heat removal

The following systems interface with, but are not part of, the RHR system:

1. Liquid radwaste
2. Condensate makeup and drawoff

3. Spent fuel pool cooling and cleanup
4. Reactor core isolation cooling
5. Reactor plant sampling
6. Service water
7. Reactor building equipment drain
8. Reactor recirculation
9. Low-pressure core sprays
10. Reactor building closed loop cooling water

Nitrogen supply interfaces with, but is not part of, the ADS system.

The following design is incorporated to assure that systems connected to the ECCS do not degrade the reliability of the ECCS function:

1. Initiation signals cause automatic recovery of all required automatic valves from the flow test mode to ECCS alignment.

   2. Various valve arrangements are provided to isolate ECCS systems from interfacing systems, including the following methods (refer to the system P&IDs in appropriate sections for specific system configuration):

   a. Locked closed, or normally closed, manually-operated, safety-related valves.

   b. Normally closed, motor- or solenoid-operated safety-related valves.

      Valve positions are administratively controlled through the use of operating and maintenance procedures to provide proper isolation between systems.

3. Where seismic Category I piping is connected to nonseismic piping, the nonseismic piping is seismically analyzed and supported up to the first anchor point beyond the seismic-nonseismic piping boundary (refer to Section 3.7A.3.3.2).

6.3.2.6 Protection Provisions

Protection provisions are included in the design of the ECCS. Protection is afforded against missiles, pipe whip, and flooding. Also accounted for in the design are thermal stresses, loadings from a LOCA, and seismic effects.

The ECCS piping and components located outside the drywell are protected from internally- and externally-generated missiles by the reinforced concrete structure of the ECCS pump rooms. Pump room layout and protection is covered in Section 6.2.3.

The ECCS is protected against the effects of pipe whip, which might result from piping failures up to and including the design basis event LOCA. This protection is provided by separation, pipe whip restraints, and energy-absorbing materials. These three methods are applied to provide protection against damage to piping and components of the ECCS which otherwise could result in a reduction of ECCS effectiveness to an unacceptable level. See Section 3.6 for criteria on pipe whip.

The component supports which protect against damage from movement and from seismic events are discussed in Section 5.4.14. The methods used to provide assurance that thermal stresses do not cause damage to the ECCS are described in Section 3.9A.3.

6.3.2.7 Provisions for Performance Testing

Periodic system and component testing provisions for the ECCS are described in Section 6.3.2.2 as part of the individual system descriptions. Section 6.3.4 further describes tests and inspections.

6.3.2.8 Manual Actions

The ECCS is actuated automatically and requires no Operator action during the first 10 min following the accident. During the long-term cooling period (after 10 min), the Operator takes action as specified in Section 6.2 to place the suppression pool cooling system in operation. Initiation of the suppression pool cooling system and the containment spray cooling system (if required) are the only manual actions required by the Operator to provide reactor and containment cooling during the course of the LOCA.

During performance of emergency operating procedures (EOPs), Operator action includes defeating the ADS logic as directed by the RPV control procedure. This is acceptable during EOP use since the Operator is more informed than the ADS logic, and in a better position to judge when and how to depressurize the RPV while minimizing transient loads and optimizing adequate core cooling. Additionally, the ADS logic's limiting assumption of no Operator action for 10 min is invalid when executing the procedures. The Operator is directed to manually emergency depressurize when the RPV water level falls to the top of active fuel (TAF). Additionally, as demonstrated in the following paragraphs, it can be concluded that defeating ADS does not increase the PCT of the fuel.

For large break LOCAs, defeating ADS is acceptable because the RPV is already depressurized due to the break. For small break LOCAs, defeating ADS is acceptable since the Operator will initiate ADS prior to when it would have initiated automatically. Automatic initiation is delayed until the completion of the 105-sec timer while manual initiation has no time delay. This 105-sec timer will delay automatic initiation of ADS to a time when RPV water has already lowered to a level below TAF. Thus, for this scenario, using EOPs will result in depressurization earlier than analyzed in the USAR.

For large steam line breaks outside of containment, the ADS system will initiate to depressurize the RPV to allow low pressure systems to inject, as shown in Table 15.6-5 and on Figures 6.3-53 through 6.3-56. Using EOPs, ADS is inhibited when RPV Level 1 is reached.

When the Operator recognizes that RPV water level cannot be maintained above TAF, he is directed to the alternate level control procedure (N2-EOP-C1). Procedure N2-EOP-C1 directs RPV emergency depressurization when RPV water level reaches TAF (and injection sources are available). ADS is not required above TAF since adequate core cooling is provided through core submergence. When the RPV is emergency depressurized, water level inside the shroud will initially swell, then level will decrease as voids collapse and inventory is lost through the SRVs. When RPV pressure falls below the shutoff head of the low-pressure ECCS, injection will commence and the RPV will be flooded above TAF.

During the blowdown, core cooling will be achieved by a combination of submergence and steam flow through the uncovered portion of the core, similar to the ADS blowdown scenario. Defeating ADS may delay initiation of emergency depressurization to the time when RPV water level decreases to the TAF (versus initiation at the completion of the 105-sec delay timer, as described in Table 15.6-5, which would occur above TAF), and therefore may cause RPV level to be lower and PCT to be higher than the values given in the SAFER/GESTR LOCA analysis[3]. This, however, is acceptable since the consequences of this accident remain the same as explained below.

Table 15.6-6 provides the assumptions used to calculate the offsite doses for steam line breaks outside secondary containment. These parameters include initial coolant isotope concentrations, mass of coolant released, fraction of isotopes released, and MSIV closure time. Since fuel damage did not occur, neither isotope concentrations nor any other input parameter are affected and PCT is not factored into the offsite dose calculation. Moreover, the conclusions drawn in Section 15.6.4.5 with regard to radiological consequences are not affected. Since the offsite release in this accident is terminated when the MSIVs are closed, and since no fuel damage has occurred (and thus no leakage from the containment will impact the release), the offsite consequences are not impacted.

For the reasons stated above, it is concluded that for a large steam line break outside of primary containment, defeating ADS is acceptable.

The LOCA analysis assumed uninterrupted LPCI flow to the reactor core during the first 10 min of the accident. In accordance with EOPs, a RHR pump may be realigned from the LPCI mode to the containment spray or suppression pool cooling mode of operation independent of the 10 min elapsed time criteria assumed in the LOCA analysis. The approach utilized in the EOPs is acceptable as these procedures contain adequate cautions to deter the Operator from premature flow diversion of RHR in the LPCI mode of operation. The guidance provided in EOPs assures that the PCT identified by the USAR LOCA analyses is not increased due to Operator realignment of the RHR system during an accident. Therefore, EOPs may result in diversion of RHR flow from the core cooling function prior to 10 min into the accident; however, such action will not increase the PCT of the fuel.

The Operator has multiple instrumentation available in the main control room to assist in assessing the post-LOCA conditions.

This instrumentation provides reactor vessel pressures, water levels, containment pressure, temperature and radiation levels, as well as indicating the operation of the ECCS. ECCS flow indication is the primary parameter available to assess proper operation of the system. Other indications such as position of valves, status of circuit breakers, and essential power bus voltage are also available to assist in determining system operating status. The electrical and instrumentation complement to the ECCS is discussed in Section 7.3. Other available instrumentation is listed in the P&IDs for the individual systems. Monitoring instrumentation available to the Operator is discussed in Chapter 5 and Section 6.2.

6.3.3 ECCS Performance Evaluation

The performance of the ECCS is determined through application of the 10CFR50 Appendix K evaluation models and then showing conformance to the acceptance criteria of 10CFR50.46. The SAFER/GESTR-LOCA Application Methodology was previously used to evaluate the ECCS performance of the GE 11 and GE 14 fuel during a postulated LOCA. The SAFER/GESTR-LOCA analytical models are documented in Section S.2 of GESTAR II[1]. The SAFER/PRIME-LOCA application methodology was used to evaluate the current ECCS performance of the GE14 and GNF2 fuel during a postulated LOCA. The SAFER/PRIME-LOCA analytical models are documented in Section S.2 of GESTAR II[1]

The ECCS performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. The accidents, as listed in Chapter 15, for which ECCS operation is required are:

15.6.6	Feedwater line break
15.6.4	Steam system piping break outside containment
15.6.5	LOCAs (inside containment)

Chapter 15 provides the radiological consequences of these events.

The updated ECCS-LOCA results are provided in Reference 3. Cycle-specific reload results are discussed in Appendix A, Section A.6.

This section presents the licensing base case of the ECCS performance evaluation in regards to input, assumptions, ECCS divisionalization, and output. Special capabilities of the plant to operate outside of the base case domain have also been analyzed. Each of these operating conditions/options is supported by its own unique ECCS performance evaluation. These case studies are documented in Chapter 15 appendices as follows:

Appendix 15B	Recirculation System Single Loop Operation
Appendix 15C	Two Safety Relief Valves (ADS Function) Out of Service
Appendix 15D	One Main Steam Isolation Valve Out of Service
Appendix 15G	Maximum Extended Load Line Limit Analysis

6.3.3.1 ECCS Bases for Technical Specifications

The MAPLHGRs calculated in this performance analysis provide the basis for Technical Specifications designed to ensure conformance with the acceptance criteria of 10CFR50.46. Minimum ECCS functional requirements are specified in Sections 6.3.3.4 and 6.3.3.5, and testing requirements are discussed in Section 6.3.4. Limits on minimum suppression pool water level are discussed in Section 6.2.

6.3.3.2 Acceptance Criteria for ECCS Performance

The applicable acceptance criteria, extracted from 10CFR50.46, are listed and for each criterion applicable parts of Section 6.3.3, where conformance is demonstrated, are indicated. A detailed description of the methods used to show compliance are shown in Section S.2.2.3.2 of GESTAR II[1].

<u>Criterion 1, Peak Cladding Temperature</u>

"The calculated maximum fuel element cladding temperature shall not exceed 2,200°F." Conformance to Criterion 1 is shown in Section 6.3.3.7.3 (Break Spectrum), 6.3.3.7.4 (Design Basis Accident), 6.3.3.7.5 (Transition Break), 6.3.3.7.6 (Small Break), and specifically in Table 6.3-5 (PCT at limiting exposure).

Criterion 2, Maximum Cladding Oxidation

"The calculated total local oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation." Conformance to Criterion 2 is shown in Table 6.3-5 (break spectrum summary).

Criterion 3, Maximum Hydrogen Generation

"The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinder surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react." Conformance to Criterion 3 is shown in Table 6.3-5.

Criterion 4, Coolable Geometry

"Calculated changes in core geometry shall be such that the core remains amenable to cooling." As described in NEDO-20566-P-A, Conformance to Criterion 4 is demonstrated by conformance to Criteria 1 and 2.

Criterion 5, Long-Term Cooling

"After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core." Conformance to Criterion 5 is demonstrated generically for GE BWRs in NEDO-20566-P-A Volume II. Briefly summarized, the core remains covered to at least the jet pump suction elevation and the uncovered region is cooled by spray cooling.

6.3.3.3 Single-Failure Considerations

The functional consequences of potential Operator errors and single failures (including those that might cause any manually-controlled, electrically-operated valve in the ECCS to move to a position that could adversely affect the ECCS), and the potential for submergence of valve motors in the ECCS are discussed in Section 6.3.1. No potential single failures are more severe than the single failures identified in Table 6.3-3. It is, therefore, only necessary to consider each of these single failures in the ECCS performance analyses.

For large breaks, failure of one of the standby diesel generators is in general the most severe failure. For small breaks, the failure of the HPCS is the most severe failure; neither failure results in unacceptable consequences.

A single failure in the ADS (one ADS valve) has no effect on large breaks. Therefore, as a matter of calculational convenience, it is assumed in all calculations that one ADS valve fails to operate in addition to the identified single failure. This assumption reduces the number of calculations required in the performance analysis and bounds the effects of one ADS valve failure and HPCS failure by itself. The only effect of the assumed ADS valve failure on the calculations is a small increase (approximately 200°F) in the calculated temperatures following small breaks.

6.3.3.4 System Performance During the Accident

In general, the system response to an accident can be described as:

1. Receiving an initiation signal,

2. A small lag time (to open all valves and have the pumps up to rated speed), and

3. ECCS flow entering the vessel.

Key ECCS actuation setpoints and time delays are provided in Table 6.3-1. The delay from the receipt of signal until the ECCS pumps have reached rated speed is subject to the physical limitations of accelerating the diesel generators and pumps. The delay time due to valve motion in the case of the high pressure system provides a suitably conservative allowance for valves available for this application. In the case of the low pressure system, the time delay for valve motion is such that the pumps are at rated speed prior to the time the vessel pressure reaches the pump shutoff pressure.

The flow delivery rates analyzed in Section 6.3.3 can be determined from the head-flow curves on Figures 6.3-3A, 6.3-4A, and 6.3-5A, and the pressure versus time plots discussed in Section 6.3.3.7. Simplified piping and instrumentation and functional control diagrams for the ECCS are provided in Section 6.3.2. The operational sequence of the ECCS for the DBA is shown in Table 6.3-2.

Operator action is not required, except as a monitoring function, during the short-term cooling period following the LOCA. During the long-term cooling period, the Operator takes action as specified in Section 6.2.2.2 to place the containment cooling system into operation.

Using the standard, approved licensing models (initial LOCA analysis) and an assumed FCV closure rate of 11 percent per second, generic BWR/5-6 analyses showed an increase of the PCT of <45°F. This incremental change (<45°F) has also been confirmed for Unit 2 using the SAFER/GESTR-LOCA methodology described in Section S.2 of GESTAR II[1]. The ECCS calculations applicable to

Unit 2 yield a PCT that can accommodate this increase without violating the 2,200°F limit of 10CFR50.46.

Provisions for limiting the FCV closure rate to 11 percent are discussed below.

ECCS analysis for the double-ended recirculation pipe break DBA takes credit for a core flow coastdown resulting from recirculation pump coastdown in the unbroken loop. A hypothesized closure of the FCV in the unbroken loop during the first few seconds of a LOCA gives rise to the question of whether degraded flow coastdown could lead to increased values of PCT. Actual recirculation FCV closure, leading to degraded flow coastdown, is not an expected consequence of a LOCA event.

Following initiation of a LOCA event, the normal recirculation control system response would tend to open the FCV or maintain its last demanded position.

In the neutron-flux mode of operation, the depressurization would cause neutron flux to decrease. Reduction of the neutron flux feedback signal again calls for more drive flow demand and, therefore, FCV opening.

In the flow control mode of operation, there is no control interaction between the two drive flow loops. The depressurization would cause no significant change with drive-flow feedback signal on the unbroken loop and, thus, no demand for change of FCV position.

It also should be noted that within the first second of the DBA LOCA, the drywell pressure increases. Drywell pressure sensors will detect this pressurization and immediately drop hydraulic pressure to the pilot lines of check valves on the FCV actuator. The drywell pressure sensors are located on instrument racks mounted outside the drywell. These sensors are identical in design and manufacturer to the pressure transmitters which provide a high drywell pressure signal to the RPS and ECCS, i.e., environmentally qualified for LOCA and post-LOCA conditions. With loss of pilot pressure, these check valves will close and lock up the FCV. Until these interlocks are cleared, no control system signal (intentional or inadvertent) can cause FCV position to change.

FMEAs have shown that, given a LOCA event, no single failure in the electronic/hydraulic controls can cause the FCV to close.

As a result of these considerations, FCV closure in the unbroken loop is not expected to occur during the LOCA event.

Even if the FCVs were signaled to close for some unlikely reason (LOCA plus two failures: failure of drywell high pressure signal such that FCV lockup does not occur, and failure of FCV controls), backup electronic velocity limiters are included in the recirculation control system to limit FCV velocity to 10 ± 1 percent actuator stroke rate. Additional multiple specific component failures in these limiters must occur to cause full closure of the FCV at velocities in excess of this value. The combined probability of occurrence of these specific failure modes during LOCA is less than 10^{-6} per year. Accordingly, the electronically limited rate of 10 ± 1 percent of FCV actuator stroke rate is considered a realistic yet conservative closure rate.

Thus, the PCT effect is concluded to be very small. The probability of FCV fast closure simultaneously with a LOCA is extremely remote. Accordingly, fast FCV closure in conjunction with the DBA LOCA is not expected to occur and need not be compared to the maximum PCT criteria of 10CFR50.46.

Shown on Figure 6.3-5C is a generic plot of the PCT versus time with and without FCV closure calculated with the methodology used in the initial LOCA analysis for the case which resulted in the largest PCT increase due to FCV closure. The initial increase in PCT is caused by the earlier loss of nucleate boiling with FCV closure. For time periods after boiling transition of the base case, the convective heat transfer coefficients for both cases are nearly identical for the remainder of the transient. This results in a higher heat removal rate for the FCV closure case and a decrease in the PCT difference to a value of 45°F at the time of reflooding. For plants which reflood later, the sensitivity to FCV closure will be smaller since the PCT difference decreases with time. The incremental change in PCT has been calculated to be <45°F for Unit 2 using the SAFER/GESTR-LOCA methodology described in Section S.2 of GESTAR II[1].

See Sections 15.3.2 and 15.4.5 for analyses of FCV failures in the recirculation system.

6.3.3.5 Use of Dual Function Components for ECCS

With the exception of the LPCI system, the systems of the ECCS are designed to accomplish only one function: to cool the reactor core following a loss of reactor coolant. To this extent, components or portions of these systems (except for pressure relief) are not required for operation of other systems that have emergency core cooling functions, or vice versa. Because either the ADS initiating signal or the overpressure signal opens the SRV, no conflict exists.

The LPCI subsystem, however, uses the RHR pumps and some of the RHR valves and piping. When the reactor water level is low, the LPCI subsystem has priority through the valve control logic over the other RHR subsystems for containment cooling. LPCI subsystem prioritization over shutdown cooling is maintained by performing manual action to realign the suppression pool suction valve.

Immediately following a LOCA, the RHR system is directed to the LPCI mode.

6.3.3.6 Limits on ECCS Parameters

The limits on the ECCS parameters are discussed in Sections 6.3.3.1 and 6.3.3.7.1. Any number of components in any given system may be out of service, up to and including the entire system. The maximum allowable out-of-service time is a function of the level of redundancy and the specified test intervals (Section 15A).

6.3.3.7 ECCS Analyses for LOCA

6.3.3.7.1 LOCA Analysis Procedures and Input Variables

The procedures approved for LOCA analysis conformance calculations are described in detail in Section S.2.2.3.2 of GESTAR II[1]. The SAFE/REFLOOD procedures were used in the initial LOCA calculations discussed in Section 6.3.3. The SAFER/GESTR-LOCA methodology was used for subsequent LOCA analyses, while the SAFER/PRIME-LOCA methodology was used for the current LOCA analysis.

The significant input variables used by the LOCA codes are listed in Table 6.3-1 and on Figure 6.3-9.

6.3.3.7.2 Accident Description

A detailed description of the LOCA calculation is provided in Section S.2.2.3.2 of GESTAR II[1] and in Section 2 of the NMP2 SAFER/GESTR-LOCA Analysis[3].

6.3.3.7.3 Break Spectrum Calculations

A complete spectrum of postulated break sizes and locations is considered in the evaluation of ECCS performance. For ease of reference, a summary of all figures and tables presented in the initial LOCA analysis is shown in Table 6.3-6. A summary of all figures and tables is presented in the NMP2 SAFER/GESTR-LOCA Analysis (Table C-1)[3].

A summary of the SAFER/GESTR-LOCA results of the break spectrum calculations is shown in Table 6.3-5 and graphically on Figure 6.3-8. Conformance to the acceptance criteria (PCT ≤2,200°F, local oxidation ≤17 percent, and core-wide metal-water reaction ≤1 percent) is demonstrated. Discussions of general characteristics for specific break sizes are included in subsequent paragraphs.

As reported in Reference 5, and further documented in Reference 6, a top peaked axial power shape makes the small break LOCA PCT limiting.

6.3.3.7.4 Large Recirculation Line Break Calculations

The characteristics that determine which is the most limiting large break are:

1. The time of calculated boiling transition.

2. The calculated hot node uncovery time.

3. The calculated hot node reflooding time.

The time of calculated boiling transition increases with decreasing break size since jet pump suction uncovery (which leads to boiling transition) is determined primarily by the break size for a particular plant. The calculated hot node uncovery time also generally increases with decreasing break size, as it is primarily determined by the inventory loss during the blowdown.

The hot node reflooding time is determined by a number of interacting phenomena such as depressurization rate, countercurrent flow, and a combination of available ECCS subsystems.

The period between hot node uncovery and reflooding is the period when the hot node has the lowest heat transfer. Hence, the break that results in the longest period during which the hot node remains uncovered results in the highest calculated PCT. If two breaks have similar times during which the hot node remains uncovered, then the larger of the two breaks will be limiting, as it would have an earlier boiling transition time (i.e., the larger break would have a more severe blowdown heat transfer analysis).

Figure 6.3-10 shows the variation with break size of the calculated time the hot node remained uncovered using the initial LOCA analysis methods. The DBA was determined to be the break that results in the highest calculated PCT using the initial LOCA analysis method. Confirmation that the DBA remains the most limiting break over the entire break spectrum is shown on Figure 6.3-8 using the SAFER/GESTR-LOCA methods (Section 5.1 of Reference 3).

As reported in Reference 5, a top peaked axial power shape makes the small break LOCA PCT limiting.

Variables from the initial LOCA analyses of the DBA are shown on Figures 6.3-11 through 6.3-20. Corresponding similar information for the SAFER/GESTR-LOCA analyses is provided in Reference 3. The key variables are:

1. Core average pressure as a function of time.

2. Core flow as a function of time.

3. Core inlet enthalpy as a function of time.

4. MCPR as a function of time.

5. Water level as a function of time.

6. Pressure as a function of time.

7. Fuel rod convective heat transfer coefficient as a function of time.

8. PCT as a function of time.

9. Average fuel temperature as a function of time.

10. PCT rod internal pressure as a function of time.

The MAPLHGR, maximum local oxidation, and PCT as a function of exposure from the initial DBA analysis are shown in Table 6.3-4. For the SAFER/GESTR-LOCA analysis[3], LOCA is not limiting from the viewpoint of MAPLHGR. See Appendix A for cycle-specific MAPLHGR information.

6.3.3.7.5 Transition Recirculation Line Break Calculations

Variables from the initial LOCA analysis of the transition (1.0 sq ft) break are shown on Figures 6.3-21 through 6.3-32. Corresponding information for the SAFER/GESTR-LOCA analysis is provided in Reference 3. The key variables are:

1. Core average pressure (large break methods) as a function of time.

2. Core flow (large break methods) as a function of time.

3. Core inlet enthalpy (large break methods) as a function of time.

4. MCPR (large break methods) as a function of time.

5. Water level (large break methods) as a function of time.

6. Pressure (large break methods) as a function of time.

7. Fuel rod convective heat transfer coefficient (large break methods) as a function of time.

8. PCT (large break methods) as a function of time.

9. Water level (small break methods) as a function of time.

10. Pressure (small break methods) as a function of time.

11. Fuel rod convective heat transfer coefficients (small break methods) as a function of time.

12. PCT (small break methods) as a function of time.

The transition recirculation line break (1.0 sq ft) PCT was also calculated to be lower than the DBA recirculation line break PCT using SAFER/GESTR-LOCA methods. This is shown on Figure 6.3-8. A detailed description of the transition recirculation line break is given in Reference 3, Section 5.1.1.

6.3.3.7.6 Small Recirculation Line Break Calculations

Variables from the initial LOCA analysis of the most severe small break are shown on Figures 6.3-33 through 6.3-36. Corresponding information for the SAFER/GESTR-LOCA analysis is provided in Reference 3. The key variables are:

1. Water level as a function of time.

2. Pressure as a function of time.

3. Convective heat transfer coefficients as a function of time.

4. PCT as a function of time.

The most severe small recirculation line break (0.1 sq ft) PCT calculated with SAFER/GESTR-LOCA methods was also lower than the DBA recirculation line break PCT. It is shown in Table 6.3-5 and on Figure 6.3-8. A detailed description is given in Reference 3, Section 5.1.1.

As reported in Reference 5, a top peaked axial power shape makes the small break LOCA PCT limiting.

6.3.3.7.7 Calculations for Other Break Locations

Reactor water level, vessel pressure, fuel rod convective heat transfer coefficients, and PCT from the initial LOCA analysis are shown on Figures 6.3-41 through 6.3-44 for the HPCS line break, Figures 6.3-45 through 6.3-48 for the feedwater line break, and Figures 6.3-49 through 6.3-52 for the main steam line break inside the containment.

Analysis was also done for the main steam line break outside the containment. Reactor water level, vessel pressure, fuel rod convective heat transfer coefficients, and PCT from the initial LOCA analysis are shown on Figures 6.3-53 through 6.3-56.

Other break locations were also analyzed with SAFER/GESTR-LOCA methods. They result in lower PCTs than the DBA recirculation line break. This is shown in Reference 3, Section 5.1.2.

As reported in Reference 5, a top peaked axial power shape makes the small break LOCA PCT limiting.

6.3.3.7.8 Updated ECCS-LOCA Results

For information on the subsequent ECCS-LOCA analyses using SAFER/GESTR-LOCA, or SAFER/PRIME-LOCA, see Reference 3.

See the latest report submitted to the NRC in accordance with 10 CFR 50.46 for current assessments against the analysis of record reference PCT resulting from reported error corrections and input changes.

6.3.3.8 LOCA Analysis Conclusions

Having shown compliance with the applicable acceptance criteria of Section 6.3.3.2, it is concluded that the ECCS will perform its function in an acceptable manner and meet all of the 10CFR50.46 acceptance criteria. The initial LOCA analysis assumed operation at or below the MAPLHGRs in Table 6.3-4.

SAFER/GESTR-LOCA analysis[3] shows acceptable compliance up to the fuel mechanical design MAPLHGR limits at all exposures; LOCA does not restrict fuel MAPLHGR operational limits.

Cycle-specific results are covered in Appendix A, Section A.6.

6.3.4 Tests and Inspections

6.3.4.1 ECCS Performance Tests

All systems of the ECCS are tested for operational ECCS function during the preoperational and/or startup test program. Each component is tested for power source, range, direction of rotation, setpoint, limit switch setting, and torque switch setting, etc. Each pump is tested for flow capacity for comparison with vendor data. (This test is also used to verify flow measuring capability.) The flow tests involve the same suction and discharge source; i.e., suppression pool or CST.

All logic elements are tested individually and then as a system to verify complete system response to emergency signals including the ability of valves to revert to the ECCS alignment from other positions.

Finally the entire system is tested for response time and flow capacity taking suction from its normal source and delivering flow into the reactor vessel. This last series of tests is performed with power supplied from both offsite power and onsite emergency power. See Chapter 14 for a discussion of preoperational testing for these systems.

6.3.4.2 Reliability Tests and Inspections

The average reliability of a standby (nonoperating) safety system is a function of the duration of the interval between periodic functional tests. The factors considered in determining the periodic test interval of the ECCS are: the desired system availability (average reliability), the number of redundant functional system success paths, the failure rates of the individual components in the system, and the schedule of periodic tests (simultaneous versus uniformly staggered versus randomly staggered). For the ECCS the above factors were used to determine test intervals[4].

All active components of the HPCS system, ADS, LPCS, and LPCI systems are designed so that they may be tested during normal plant operation. Full flow test capability is provided by a test line back to the suction source. The full flow test is used to verify the capacity of each ECCS pump loop while the plant remains undisturbed in the power generation mode. In addition, each individual valve may be tested during normal plant operation. Input jacks are provided so that by racking out the injection valve breaker, each ECCS loop can be tested for response time.

All active components of the ADS, except the SRVs and their associated solenoid valves, are designed so that they may be tested during normal plant operation. The ADS SRVs and associated solenoid valves are tested per the Technical Specifications each fuel cycle, usually during a refueling outage.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Section 7.3.1. The emergency power system, which supplies electrical power to the ECCS in the event that offsite power is unavailable, is tested as described in Section 8.3.1. The frequency of testing is specified in Technical Specifications. Visual inspections of all ECCS components located outside the drywell can be made at any time during power operation. Components inside the drywell can be visually inspected only during periods of access to the drywell. When the reactor vessel is open, the spargers and other internals can be inspected.

6.3.4.2.1 HPCS Testing

The HPCS can be tested at full flow with CST water at any time during plant operation, except when the reactor vessel water level is low, or when the condensate level in the CST is below the reserve level, or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while the

HPCS is being tested, the system returns automatically to the operating mode. The two MOVs in the test line to the condensate storage system are interlocked closed when the suction valve from the suppression pool is open.

A design flow functional test of the HPCS over the operating pressure and flow range is performed by pumping water from the CST and back through the full flow test return line to the CST.

The suction valve from the suppression pool and the discharge valve to the reactor remain closed. These two valves are tested separately to ensure their operability.

The HPCS test conditions are tabulated on the HPCS process diagram (Figure 6.3-1).

6.3.4.2.2 ADS Testing

At least once per 24 months:

1. Perform a leak rate test for ADS SRV pneumatic operators by pressurizing each ADS accumulator at 178 psig up to its supply header isolation check valve with the SRV actuator in the open position. The valve is not required to be open. Total leakage rate for each SRV shall not exceed 0.5 scfh for the SRV actuated by either of the ADS solenoids.

2. Perform a leak rate test for the safety-related ADS accumulator pneumatic supply system (including special emergency tube trailer supply piping) up to SRV actuators/operators. The valve is not required to be open. With the SRV operator actuated by either of the ADS solenoids, and with ADS accumulators at 178 psig, and with ADS nitrogen receiving tanks at a minimum of 365 psig (high pressure alarm upper limit), the leakage rates shall not exceed the following limits:

    a. For the ADS SRV actuators, supply header and accumulators, and the nitrogen receiving tank for SRVs 2MSS*PSV121, 126 and 127, maximum allowable leakage is 3 scfh.

    b. For the ADS SRV actuators, supply header and accumulators, and the nitrogen receiving tank for SRVs 2MSS*PSV129, 130, 134 and 137, maximum allowable leakage is 4 scfh.

Additional periodic surveillance testing requirements for the ADS are described in Technical Specifications. During plant operation the ADS can be checked as discussed in Section 7.3.1.

6.3.4.2.3 LPCS Testing

The LPCS pump and valves are tested periodically during reactor operation. With the injection valve closed and the return line open to the suppression pool, full flow pump capability is demonstrated. The injection valve and the check valve are tested in a manner similar to that used for the LPCI valves. The system test conditions during reactor shutdown are shown on the LPCS system process diagram (Figure 6.3-2).

6.3.4.2.4 LPCI Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated on Figure 5.4-14. During plant operation, this test does not inject cold water into the reactor because the injection line check valve is held closed by vessel pressure, which is higher than the pump pressure. The injection line portion may be tested with reactor water when the reactor is shut down and when a closed system loop is created. This prevents unnecessary thermal stresses.

To test the LPCI pump at rated flow, the test line valve to the suppression pool is opened, the pump suction valve from the suppression pool is opened (this valve is normally open), and the pumps are started using the remote/manual switches in main control room. Correct operation is determined by observing the instruments in the main control room.

If an initiation signal occurs during the test, the LPCI system automatically returns to the operating mode. The valves in the test bypass lines are closed automatically to assure that the LPCI pump discharge is correctly routed to the vessel.

6.3.5 Instrumentation Requirements

Design details including redundancy and logic of the ECCS instrumentation are discussed in Section 7.3.

All instrumentation required for automatic and manual initiation of the HPCS, LPCS, LPCI, and ADS is discussed in Section 7.3.2 and is designed to meet the requirements of IEEE-279 and other applicable regulatory requirements. The HPCS, LPCS, LPCI, and ADS can be manually initiated from the main control room.

The HPCS, LPCS, and LPCI are automatically initiated on low reactor water level or high drywell pressure. (See Table 6.3-1 for specific initiation levels for each system.) The ADS is automatically actuated by sensed variables for reactor vessel low water level plus indication that at least one LPCI or LPCS pump is operating. The HPCS, LPCS, and LPCI automatically return from system flow test modes to the emergency core cooling mode of operation following receipt of an automatic initiation signal. The LPCS and LPCI system injection into the RPV begin when reactor pressure decreases to system discharge shutoff pressure.

HPCS injection begins as soon as the HPCS pump is up to speed and the injection valve is open, since the HPCS is capable of injecting water into the RPV over a pressure range from approximately 1100 psid to 0 psid (psid = differential pressure between RPV and pump suction source). See Figure 6.3-3a.

6.3.6 References

1. General Electric Standard Application for Reactor Fuel, including United States Supplement, NEDE-24011-P-A and NEDE-24011-P-A-US (latest approved revision).

2. General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50, Appendix K, NEDE-20566-P-A, September 1986.

3. Nine Mile Point Nuclear Power Station - Unit 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis, NEDC-31830P Rev. 1, November 1990; Nine Mile Point Unit 2 ECCS-LOCA Evaluation Update for GE 11, GE-NE-J1103938-07-02P, January 2002; Nine Mile Point-2 SAFER/GESTR Loss-of-Coolant Accident Analysis for GE 14 Fuel, GE-NE-0000-0024-6517-R0, February 2004; Nine Mile Point Nuclear Station Unit 2 Extended Power Uprate: ECCS-LOCA SAFER/GESTR, 0000-0080-7568-R1, February 2009; Nine Mile Point Nuclear Station Unit 2 MELLLA+: ECCS-LOCA SAFER/GESTR, 0000-0117-0322-R2, November 2012; and Nine Mile Point Nuclear Station Unit 2 MELLLA+: ECCS-LOCA SAFER/PRIME, 0000-0162-4214-R0, August 2013; Nine Mile Point Unit 2 GNF2 ECCS-LOCA Evaluation, 002N4205-R0, December 2015.

4. Hirsch, H. M. Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems, January 1973 (NEDO-10739).

5. General Electric Company Letter, A. Lingenfelter to Nine Mile Point Nuclear Station, Unit 2 - 10CFR50.46 Notification Letter 2006-01, "Impact of Top Peaked Power Shape for Small Break LOCA Analysis," July 28, 2006.

6. General Electric Company, Nine Mile Point Nuclear Station Unit 2 APRM/RBM/Technical Specifications/Maximum Extended Load Line Limit Analysis (ARTS/MELLLA), NEDC-33286P, March 2007.

7. GEH Report 0000-0081-8438-R1, “Nine Mile Point Nuclear Station Unit 2 – Extended Power Uprate, Task 0400: Containment System Response,” August 2008.

8. NRC Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems,” January 11, 2008.

TABLE 6.3-1

SIGNIFICANT INPUT VARIABLES USED IN THE SAFER/GESTR LOSS-OF-COOLANT ACCIDENT ANALYSIS[3]

(Cycle-specific fuel parameters are covered in Appendix A, Table A.6-2)

	Nominal Analysis	Appendix K Analysis
A. Plant Parameters		
Core thermal power	3,467 MWt	3,536 MWt
Vessel steam output	15.0×10^6 lbm/hr	15.35×10^6 lbm/hr
Corresponding percent of rated steam flow	100	102
Vessel steam dome pressure	1,055 psia	1,055 psia
Maximum area of recirculation suction line break	3.1 ft^2	3.1 ft^2
B. ECCS Parameters		
B.1 LPCI system		
Vessel pressure at which flow may commence	≤225 psid (vessel to drywell)	
Minimum rated flow at vessel pressure	6660 gpm @ 0 psid, 6360 gpm @ 20 psid, 5960 gpm @ 45 psid, 5570 gpm @ 67 psid, 5160 gpm @ 90 psid, 4710 gpm @ 112 psid, 4210 gpm @ 135 psid, 3600 gpm @ 150 psid, 2200 gpm @ 190 psid, 1000 gpm @ 190.1 psid, 0 gpm @ 210 psid (vessel to drywell)	
Initiating signals:		
Low water level (L1) or High drywell pressure	0.0 ft above top of active fuel 2.0 psig	

TABLE 6.3-1 (Cont'd.)

	Maximum allowable time delay from initiating signal to pumps at rated speed and capable of rated flow (including diesel generator start/load time)	66.3 sec(4)
	Pressure at which injection valve may open	225 psig(1)
	Maximum allowable injection valve stroke time	25 sec
B.2	LPCS system	
	Vessel pressure at which flow may commence	≤289 psid (vessel to drywell)
	Minimum rated flow at vessel pressure	6600 gpm @ 0 psid, 6250 gpm @ 30 psid, 5900 gpm @ 58 psid, 5520 gpm @ 87 psid, 5110 gpm @ 116 psid, 4660 gpm @ 144 psid, 4170 gpm @ 173 psid, 3610 gpm @ 202 psid, 2950 gpm @ 231 psid, 2080 gpm @ 260 psid, 0 gpm @ 289 psid (vessel to drywell)
	Initiating signals:	
	Low water level (L1) or High drywell pressure	0.0 ft above top of active fuel 2.0 psig
	Minimum runout flow	6,600 gpm

TABLE 6.3-1 (Cont'd.)

	Maximum allowed delay time from initiating signal to pump at rated speed and capable of rated flow (including diesel generator start/load time)	67.8 sec[4]
	Pressure at which injection valve may open	305 psig[2]
	Maximum allowable injection valve stroke time	25 sec
B.3	HPCS system	
	Vessel pressure at which flow may commence	1175 psid (vessel to source)
	Minimum rated flow available at vessel pressure	6250 gpm @ 0 psid, 6250 gpm @ 100 psid, 1800 gpm @ 980 psid, 0 gpm @ 1080 psid (vessel to source)
	Initiating signals:	
	Low water level (L2) or High drywell pressure	7.6 ft above top of active fuel 2.0 psig
	Minimum runout flow	6,250 gpm
	Maximum allowed delay time from initiating signal to pump at rated speed and capable of rated flow and injection valve wide open (including diesel generator start/load time)	53 sec

TABLE 6.3-1 (Cont'd.)

B.4 ADS system			
Total number of valves installed	7		
Number of valves used in analysis (also see Appendix 15C)	6		
Minimum flow capacity of six valves at pressure	4.896×10^{6} lbm/hr 1,080 psig		
Initiating signals:			
Low water level (L1) and Signal that at least one LPCS or LPCI pump is running (pump discharge pressure)	0.0 ft above top of active fuel LPCS (145) psig LPCI 125 psig		
Maximum delay time from all initiating signals completed to the time valves are open	120 sec		
C. <u>Fuel Parameters[3][6]</u>			
Fuel type	<u>BP8x8R/P8x8R</u>	<u>GE8x8EB/NB</u>	<u>GE11</u>
Fuel bundle geometry	8x8	8x8	9x9
Lattice	C	C	C
Number of fueled rods/assembly	62	60	66 (full length) 8 (part length)
Peak LHGR (kW/ft)			
- Appendix K	13.4	14.4	14.4
- Nominal	12.8	13.8	13.8
MAPLHGR (kW/ft)	13.0	14.0	12.9
Initial MCPR			
- Nominal	1.19	1.19	1.19
- Appendix K	1.17	1.17	1.17

TABLE 6.3-1 (Cont'd.)

Fuel type	BP8x8R/P8x8R	GE8x8EB/NB	GE11
Axial peaking factor	1.4	1.4	1.4
Worst-case pellet exposure for ECCS evaluation (MWd/MTU)[5]	23,000	14,590	14,600

(1) Corresponds to injection valve differential pressure of 8 psid.

(2) Corresponds to injection valve differential pressure of 0 psid.

(3) LOCA and isolation transient analyses use a maximum vessel to source differential pressure of 1175 psid for HPCS flow; the acceptability of this HPCS pump head capability has been demonstrated by the analyses during isolated reactor conditions with the two SRVs out of service and +3 percent tolerance allowance for the remaining SRV setpoints.

(4) Maximum time includes diesel generator startup and loading sequence time after a LOCA; pumps are up to speed capable of rated flow and injection valve open (assuming permissive received).

(5) Represents the limiting operating condition resulting in the maximum calculated PCT at any time in the fuel lifetime.

(6) Additional cycle-specific fuel information is provided in Appendix A, Section A.6, as it applies to LOCA analyses.

TABLE 6.3-2

OPERATIONAL SEQUENCE OF EMERGENCY CORE COOLING SYSTEMS FOR SAFER/GESTR-LOCA ANALYSIS[3] OF THE DESIGN BASIS ACCIDENT[1]

Time (sec)	Event
0	Design basis LOCA assumed to start; normal auxiliary power assumed to be lost.
~0	Drywell high pressure[2] reached. All diesel generators signaled to start; scram; HPCS, LPCS, LPCI signaled to start on high drywell pressure.
~1	Reactor low water level reached providing additional scram signal.
~5	Reactor low-low water level reached. HPCS receives second signal to start (first signal neglected)[2].
~8	Reactor low-low-low water level reached. Second signal (backup) to start diesel generators; second signal to start LPCI and LPCS (first signal neglected)[2]; autodepressurization sequence begins; MSIVs signaled to close.
~31	HPCS diesel generators ready to load; energize HPCS pump motor; open HPCS injection valve[3].
~31	Divisions 1 and 2 diesel generators ready to load.
~52	HPCS injection valve open and pump at design flow, which completes HPCS startup[3].
~41	Pressure permissive for LPCS injection valve reached.
~41	Pressure permissive for LPCI injection valve reached. LPCI and LPCS pumps at rated speed.
~66	LPCS pump at rated flow, LPCS injection valve open, which completes the LPCS startups[3].
~66	LPCI pump at rated flow and LPCI injection valve open which completes LPCI startup.
<3 min	Core effectively reflooded assuming worst single failure; heatup terminated.

TABLE 6.3-2 (Cont'd.)

Time (sec)	Event
≥10 min	Operator shifts to suppression pool cooling.

(1) For the purpose of all but the next to last entry on this table, all ECCS equipment is assumed to function as designed. Performance analysis calculations consider the effects of single equipment failures (Sections 6.3.2.5 and 6.3.3.3).

(2) No credit is taken in the LOCA analysis for ECCS start on the high drywell pressure signal. Credit is taken for scram and diesel generator start on high drywell pressure.

(3) HPCS considered failed for the limiting case.

TABLE 6.3-3

SINGLE ACTIVE FAILURES CONSIDERED IN THE ECCS PERFORMANCE EVALUATION[1]

Assumed Failure	Suction Break Systems Remaining[2,3]
Division II standby diesel generator	6 ADS, HPCS, LPCS, 1 LPCI
Division I standby diesel generator	6 ADS, HPCS, 2 LPCI
HPCS	6 ADS, LPCS, 3 LPCI

(1) Other postulated failures are not specially considered because they all result in at least as much ECCS capacity as one of the above designed failures.

(2) Systems remaining, as identified in this table, are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS in which the break is assumed.

(3) Analysis performed with six of the seven installed ADS valves (see Section 6.3.3.3 and Appendix 15C, Section 15C.6).

TABLE 6.3-4

MAPLHGR, MAXIMUM LOCAL OXIDATION, AND PEAK CLAD TEMPERATURE VERSUS EXPOSURE (INITIAL DBA LOCA ANALYSIS)[2]

(Cycle-specific results are covered in Appendix A, Section A.6)

Average Planar Exposure (MWD/T)	MAPLHGR[2] (kW/ft)	PCT[2] (°F)	Oxid[1][2] (Frac)
Fuel Type BP8CRB219			
200	11.9	1904	0.009
1,000	12.0	1898	0.008
5,000	12.1	1865	0.007
10,000	12.2	1859	0.007
15,000	12.2	1874	0.007
20,000	12.2	1878	0.008
25,000	11.7	1828	0.006
30,000	11.3	1765	0.005
35,000	10.7	1695	0.004
40,000	10.1	1637	0.003
45,000	9.5	1579	0.002
Fuel Type P8CRB176			
200	12.0	1901	0.009
1,000	12.1	1901	0.009
5,000	12.7	1903	0.008
10,000	12.8	1905	0.008
15,000	12.9	1921	0.009
20,000	12.8	1913	0.008
25,000	11.8	1806	0.006
30,000	10.9	1697	0.004
35,000	10.1	1608	0.003
40,000	9.4	1549	0.002
45,000	8.8	1487	0.001
Fuel Type P8CRB071			
200	11.5	1802	0.006
1,000	11.4	1770	0.005
5,000	11.4	1728	0.004
10,000	11.5	1724	0.004
15,000	11.5	1723	0.004
20,000	11.1	1686	0.004
25,000	10.4	1633	0.003
30,000	9.8	1571	0.002
35,000	9.1	1499	0.002

TABLE 6.3-4 (Cont'd.)

Average Planar Exposure (MWD/T)	MAPLHGR[2] (kW/ft)	PCT[2] (°F)	Oxid[1][2] (Frac)
Fuel Type P8CRB071 (Cont'd.)			
40,000	8.5	1425	0.001
45,000	7.8	1355	0.001

(1) The core-wide metal-water reaction has been calculated using Method 1 described in Reference 2. The value is 0.07%.

(2) The bounding MAPLHGR values used in the SAFER/GESTR-LOCA analysis (Reference 3) are higher than the expected thermal-mechanical MAPLHGR limits for the fuel. Therefore, MAPLHGR is not limited by LOCA considerations. The limiting case is HPCS diesel generator failure during the DBA (3.1 ft^2) recirculation suction line break. All applicable criteria are satisfied. Cycle-specific results and MAPLHGR considerations are provided in Appendix A, Section A.6.

TABLE 6.3-5

SUMMARY OF RESULTS OF SAFER/GESTR-LOCA ANALYSIS[3]

(Cycle-specific results are covered in Appendix A, Section A.6)

Break Size	Location	Single Failure	PCT (°F)	Peak Local Oxidation[6] (%)
3.1 sq ft (DBA)	Recirc. suction break	HPCS diesel generator failure	1,255[1] 1,250[2] 853[3] 1,240[4]	<0.3
1.0 sq ft	Recirc. suction break	HPCS diesel generator failure	935[2] 805[3]	<0.3
0.09-0.10 sq ft[5]	Recirc. suction break	HPCS diesel generator failure	1,005[2] 846[3]	<0.3

(1) Licensing basis PCT.
(2) Appendix K analysis.
(3) Nominal analysis.
(4) Upper bound PCT.
(5) For small breaks, maximum nominal PCT is calculated for 0.10 ft^2 break, and maximum Appendix K PCT is calculated for 0.09 ft^2 break.
(6) Core-wide metal-water reaction is less than 0.1 percent for all cases.

TABLE 6.3-6
KEY TO FIGURE NUMBERS*

		Transition Recirculation Line Breaks		Small Recirculation Line Break	Other Break Locations			
	Large Recirculation Line Breaks DBA	1.0 ft^2 Large Break Method	1.0 ft^2 Small Break Method	0.09 ft^2 Highest Temp Small Break	Core Spray Line	Feedwater Line	Main Steam Line Inside Containment	Main Steam Line Outside Containment
Core average pressure	11	21	-	-	-	-	-	-
Core average inlet flow	12	22	-	-	-	-	-	-
Core inlet enthalpy	13	23	-	-	-	-	-	-
Minimum critical power ratio	14	24	-	-	-	-	-	-
Water level inside shroud	15	25	29	33	41	45	49	53
Reactor vessel pressure	16	26	30	34	42	46	50	54
Convective heat transfer coefficient	17	27	31	35	43	47	51	55
Peak cladding temperature (PCT)	18	28	32	36	44	48	52	56
Average fuel temperature	19	-	-	-	-	-	-	-
PCT rod internal pressure	20	-	-	-	-	-	-	-
Normalized power vs. time	9	9	9	9	9	9	9	9
Peak cladding temperature and peak local oxidation vs. break area	8	8	8	8	8	8	8	8
Total time for which highest powered node remains uncovered vs. break area	10	-	-	-	-	-	-	-

* All figure numbers refer to figures in Section 6.3.

TABLE 6.3-6a
KEY TO FIGURE NUMBERS*

	Large Recirculation Line Break DBA	Small Recirculation Line Break 0.07 ft^2
Hot and average channel water levels	57	61
Reactor vessel pressure	58	62
Convective heat transfer coefficient	59	63
Peak cladding temperature	60	64

*Note: Figures 6.3-57 through 6.3-64 are associated with the current ECCS-LOCA analyses.

6.4 HABITABILITY SYSTEMS

Habitability systems are provided to ensure that the plant Operators can remain in the main control room and take actions to operate the plant safely under normal conditions and to maintain it in a safe condition under all accident conditions.

The main control room habitability systems include missile protection, radiation shielding, radiation monitoring, air filtration and ventilation systems, lighting, personnel and administrative support, and fire protection.

Detailed descriptions of the various habitability systems and provisions are discussed in the following sections:

Evaluation of Potential Accidents	2.2.3
Conformance with NRC General Design Criteria	3.1
Wind and Tornado Loadings	3.3
Water Level (Flood) Design	3.4
Missile Protection	3.5
Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping	3.6
Seismic Qualification of Category I Instrumentation and Electrical Equipment	3.10
Environmental Design of Mechanical and Electrical Equipment	3.11
Radiation Protection Design Features	12.3
Plant Chilled Water System	9.4.10
Control Building Heating, Ventilating, and Air Conditioning System	9.4.1
Fire Protection System	9.5.1
Lighting Systems	9.5.3
Onsite Power System	8.3
Radiation Instrumentation and Monitoring	11.5, 12.3.4
Engineered Safety Features Systems	7.3

Equipment and systems are discussed in this section only as necessary to describe their connection with main control room habitability. References to other sections are made where appropriate.

6.4.1 Design Basis

The main control room is designed so that it provides a location from which the reactor may be safely operated during all modes of plant operation. Access to the control room to provide for food and personal comfort items is provided via analyzed routes as found on Figure 12.3-69. This includes a 30-day period following the DBA. The main control room habitability systems:

1. Provide the capability to detect and limit the introduction of radioactive material and smoke into the main control room.

2. Provide the occupants with fresh, filtered breathing air and a comfortable working atmosphere.

3. Provide the occupants with fire protection warning and firefighting equipment.

4. Maintain acceptable temperature and humidity conditions.

5. Provide the occupants with respiratory, eye, and skin protection for emergency use within areas of the main control room pressure boundary.

The main control room envelope or pressure boundary includes all instrumentation and controls necessary for safe shutdown of the plant and is limited to those areas requiring Operator access during and after a DBA.

The radiation exposure of main control room personnel through the duration of any one of the postulated DBAs discussed in Chapter 15 does not exceed the criteria set by 10CFR50.67.

The main control room air conditioning system is designed to provide a temperature condition of 75°F, which is based on optimum room conditions for personal comfort as established by the American Society of Heating, Refrigeration and Air Conditioning Engineers. The system equipment has sufficient surplus cooling capacity to maintain these conditions during normal and post-accident modes of operation such as LOCA, LOOP, and concurrent single failure, including operation with outdoor air diverted through a safety-related charcoal air filter train, as a result of a monitored smoke, high-radiation condition at the outdoor air intake, or LOCA signal.

All components of the HVAC systems serving the main control room that are required to ensure main control room habitability and essential equipment operations are redundant, Category I, powered from Class 1E buses, and Safety Class 3.

If there is a LOOP, power to the main control room air conditioning equipment is interrupted for about 60 sec. No significant temperature rise within the main control room is expected before the system is returned to operation via emergency power from the standby diesel generators.

Two redundant, 100-percent capacity water chillers supply chilled water to two 100-percent capacity air supply systems. If a failure occurs in either chilled water system or its associated air supply system, an alarm is annunciated in the main control room and the redundant system is automatically placed in operation. The control building chilled water system is described in Section 9.4.10. Service water (Section 9.2.1) can be utilized as an alternate cooling medium.

Instrumentation is provided to warn the Operators of dangerous conditions that could affect their lives and safety. Firefighting equipment is also supplied. Maintaining a positive pressure in the main control room provides a continuous purge of the main control room and also protects the Operators against infiltration of smoke or airborne radioactivity from the surrounding areas. Cables and pipes penetrating the main control room pressure boundary are sealed. This aids in the pressurization of the main control room and also limits the spread of fire and smoke that may enter pipe or cable chases.

6.4.2 System Design

6.4.2.1 Definition of the Main Control Room Envelope

The main control room envelope consists of all rooms and areas located in the main control room (el 306 ft) and relay room (el 288 ft 6 in) of the control building. Included in the envelope are the main control room, relay room, instrument shop, training room, Shift Manager's (SM) office, lunch room, toilets, corridors, work release room and HVAC equipment rooms. Airtight doors are provided at access points to and from the main control room envelope.

6.4.2.2 Ventilation System Design

The main control room HVAC system is described in detail in Section 9.4.1.

Figure 1.2-2 shows the plant layout, including the location of potential radiological release points with respect to the main control room air intakes. Potential sources of toxic gas release are identified in Section 2.2. A description of main control room instrumentation for monitoring radioactivity is given in Sections 11.5 and 12.3.4. Protection of the main control room

HVAC system from internally-generated missiles is discussed in Section 3.5.

Smoke removal from the main control room is achieved by a separate smoke removal fan which uses normal HVAC ductwork (Section 9.4.1). The air conditioning unit serving the main control room is turned off during the smoke removal mode.

Qualitative smoke evaluations have been performed for NMP2. The evaluations assessed the effects of both external and internal fire/smoke events on the capability to maintain reactor control from either the control room or remote shutdown panels. The evaluations considered various plant design and procedural criteria in accordance with RG 1.196, "Control Room Habitability at Light Water Nuclear Power Plants," and NEI 99-03, "Control Room Habitability Guidance," Revision 1. The evaluations confirmed that egress pathways to and including the remote shutdown panels are served by ventilation systems independent of the control room and that no single smoke/fire event could preclude use of both the control room and remote shutdown panels. Removal of radioiodines from the main control room ventilation outdoor air supply during a DBA is accomplished through use of charcoal filter trains. To comply with GDC 19, Appendix A of 10CFR50 and 10CFR50.67, two 100-percent redundant charcoal filter trains are provided. The main control room charcoal filter trains are designed in accordance with RG 1.52. Both filter trains and associated air handling equipment, designed to Category I, are located within the main control room pressure boundary.

Each train is rated to process 100 percent of the required system airflow. Outdoor air is supplied from the outdoor air intake. Separate intakes provide alternative sources of outdoor air with the capability of selecting either source from the main control room. Redundant radiation monitors in the main control room air supply duct system monitor the radiation level of outdoor air.

6.4.2.3 Leak-tightness

The main control room envelope boundary is designed with low leakage construction to minimize the potential for the infiltration of air into the main control room. The walls, floor, and roof are constructed of poured-in-place reinforced concrete that is essentially leak-tight. The access doors are of airtight design with self-closing devices that shut the doors automatically following the passage of personnel. All cable and air duct penetrations have fire-retardant seals that provide leak-tight construction.

The main control room in-leakage analysis was performed using the methods and assumptions given in RG 1.78 and conform with general design criteria discussed in Section 3.1.

The leak paths considered are concrete walls and floors, wall and floor joints, doors with frames, electric cable penetrations, duct penetrations, and pipe penetrations.

The system that pressurizes the main control room is described in Section 9.4.1. A periodic test is performed to verify that the makeup airflow is ±10 percent of design value.

Tracer gas testing is performed periodically using the constant injection method of ASTM E741-00, "Standard Test Method for Determining Air Change in a Single Zone by Means of a Tracer Gas Dilution." For the constant injection method, a constant flow of tracer gas is injected into the control room envelope (CRE) until the resulting concentration reaches a steady state value. This occurs when the amount of tracer gas entering the CRE is the same as the amount leaving the CRE. By injecting the tracer gas in the outside airflow used for pressurization of the envelope, an estimate of the filtered and unfiltered airflow that provides this pressurization can be made by measuring the concentration of tracer gas in the outside airflow while at the same time measuring the steady state concentration in the CRE.

6.4.2.4 Interaction with Other Zones and Pressure-Containing Equipment

The main control room air conditioning system is provided with radiation detectors. A high radiation or LOCA signal automatically diverts airflow from the air intake through the charcoal filter train.

6.4.2.5 Shielding Design

The floor plan of the main control room is provided on Figure 1.2-15. The main control room shielding, air supply system, and administrative procedures are such that the amount of radiation received by personnel during an accident would be within the value of 5 rem TEDE specified in 10CFR50.67.

Shielding of the control room is provided by reinforced concrete floors and walls of the following thicknesses:

Structure	Envelope Boundary	Minimum Concrete Thickness
Walls	All exterior walls of control building	2'
	Interior walls	1'
Floor slabs	Main control room, floor el 306'	0'-9"

Control building roof, low point el 326' high point el 328'	2'

Section 12.3.2 discusses the design objectives of shielding provided for the main control room envelope.

6.4.2.6 Portable Self-Contained Air Breathing Units

Ten full-face pressure demand self-contained breathing apparatuses (SCBA) which conform to NIOSH standards are supplied in the main control room envelope. Additionally, at least one spare air bottle per SCBA is supplied. Each SCBA supplies an Operator for approximately 30 min during moderate exertion. Operator training is provided in donning and operating this equipment. Inspection of SCBAs is performed periodically and after each use to ensure operational readiness.

Ten full-face respirators with high-efficiency particulate air (HEPA) filters are also provided in the main control room envelope.

6.4.3 System Operational Procedures

During normal and emergency operation, the main control room Operator selects the air handling unit that operates to maintain design temperatures in the main control room. Periodically the operating unit is stopped and the standby unit started so that the service time of both units is approximately equal. In the event the operating unit fails, the standby unit starts automatically.

6.4.4 Design Evaluation

6.4.4.1 Radiological Protection

Under normal plant conditions, outside air enters the main control room through either of two local outside air intakes located on the east and west sides of the control building. Each local air intake is capable of providing 100 percent of the fresh air required in the control room envelope. The two air intake ducts combine to form one common duct. Upon detection of a high radiation level by radiation monitors located in the common ductwork or a LOCA signal, airflow is automatically diverted to special charcoal/HEPA filter trains. Isolation valves in the unfiltered duct close immediately upon receiving the high radiation signal. All habitability systems are designed to meet the single-failure criterion.

Originally, the FMEA for the control room habitability system (control building air conditioning) was contained in the Unit 2 FMEA document, which is historical. FMEAs for plant systems are now performed and controlled by the design process.

6.4.5 Testing and Inspection

Preoperational testing of equipment is described in Chapter 14, Initial Test Program.

Surveillance testing is conducted as prescribed in Technical Specifications and TRM Section 3.7.2.

A CRE habitability program has been established to ensure that CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge.

6.4.6 Instrumentation Requirements

The instrumentation requirements for the main control room area HVAC system are described in Section 9.4.1.5.2. The instrumentation requirements for the control building chilled water system which supplies chilled water to the main control room air conditioning units is described in Section 9.4.10.1.5.

The ESFs for the main control room area HVAC system and the chilled water system are described in Section 7.3.1.

Conformance with GDC 19 is described in Section 3.1.2.19.

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 Engineered Safety Feature Filter Systems

The filter systems required to perform safety-related functions following a DBA are:

1. Standby gas treatment system.

2. Control building supply air system special filter train.

The control building supply air special filter train system is discussed in Sections 9.4.1 and 6.4. The SGTS is discussed in this section.

6.5.1.1 Design Bases

The design bases of the SGTS are as follows:

1. To limit the release of radioactive gases from the reactor building to the environment within the criteria of 10CFR50.67 in the event of a LOCA.

2. To maintain a negative pressure in the reactor building under accident conditions.

3. To provide redundant filter trains, each train is physically separated, so that damage to one train does not cause damage to the other.

4. To provide SGTS filters, fans, and associated components that are sized for at least one reactor building volume air change per 24-hr period.

5. The SGTS is designed to Category I requirements. The SGTS electrical components are Class 1E equipment.

6. The SGTS charcoal filter assemblies are designed in accordance with RG 1.52 (Section 1.8).

7. The SGTS filter assemblies and appurtenances are designed to withstand operational and environmental conditions specified in Table 9.4-1.

6.5.1.2 System Design

6.5.1.2.1 General System Description

The SGTS is schematically shown on Figure 9.4-8. Design data of the SGTS principal equipment are listed in Table 6.5-1.

The SGTS consists of two identical, parallel, physically separated, 100-percent capacity air filtration assemblies with associated piping, valves, controls, and centrifugal exhaust fans. Effluents from the SGTS connect to a common exhaust line discharging to the exhaust tunnel leading to the main stack. The SGTS draws air from the reactor building.

6.5.1.2.1.1 SGTS Modes of Operation

The SGTS has three modes of operation:

1. Safety-Related Mode - To maintain negative pressure in the reactor building secondary containment (post-LOCA) via connection to the reactor building recirculation ventilation system.

2. Nonsafety-Related Mode - To provide charcoal filtration of the primary containment atmosphere when inerting (startup) or deinerting (shutdown) via connection to the CPS full-flow 20-in line.

3. Nonsafety-Related Mode - To provide charcoal filtration of the primary containment atmosphere during normal power operation to control primary containment pressure via connection to the CPS 2-in bypass line.

Within 25 sec of a high radiation or LOCA signal, the SGTS draws 4,000 cfm from the discharge duct of the emergency recirculation unit cooler (Section 9.4.2) to either maintain or restore a subatmospheric pressure within the reactor building.

The SGTS is started automatically by any of the following signals:

1. High radiation or low airflow in the exhaust ducts above and below the refueling floor.

2. High pressure in the drywell.

3. Low reactor water level.

The SGTS can also be started manually and used to exhaust the primary containment purge system (Section 9.4.2.2.3).

The Plant Operator can stop one of the SGTS filter trains from the main control room after system initiation is completed. Because of the possibility of iodine desorption and charcoal ignition at high temperatures, a deluge system is provided for the charcoal adsorber section of the SGTS filter trains. Each charcoal bed has a temperature switch to detect any abnormal temperature rise at the outlet of the charcoal adsorber. When the temperature exceeds a predetermined setpoint, there is an alarm in the main control room, the exhaust fan is manually stopped and, if warranted, the fire protection system is manually initiated.

6.5.1.2.2 System Component Description

Principal system components are listed and described in Table 6.5-1. The SGTS consists of two 100-percent capacity filter trains, each of which consists of the following components in series:

1. A demister (moisture separator) to remove entrained water droplets and mist from the entering airstream.

2. An electric heating coil powered from Class 1E buses to reduce the relative humidity of the airstream to 70 percent.

3. A bank of prefilters to remove particulates from the airstream. The prefilters have 78-percent efficiency based on ASHRAE Standard 52-76.

4. A bank of HEPA filters to remove virtually all airborne particulates from the airstream. The HEPA filters have a minimum filtration efficiency of 99.97 percent for 0.3 micron diameter homogeneous particulates of dioctylphthalate (DOP) based on tests performed in accordance with MIL-STD-282.

5. A 4-in nominal depth bank of charcoal adsorber filters. Filter elements are of an all-welded, gasketless design and are sized for a maximum air velocity of 40 fpm through the charcoal at rated airflow. The adsorber material is activated coconut shell charcoal, impregnated for iodine and methyl iodine adsorption.

6. A second bank of HEPA filters identical to Item 4 above, to capture charcoal particles that may escape from the charcoal filters.

All the components listed above are mounted in an all-welded steel housing. Each charcoal filter train has an integrally mounted water (deluge) fire extinguishing facility consisting of discharge nozzles and distribution pipe. Temperature switches are provided for each charcoal bed adsorber section for annunciation in the event of high temperature. Housing floor drains are provided for the demister, the occasional washdown required for decontamination, and the deluge system in the event of a fire, in accordance with the recommendations of ERDA 76-21.

A 4,000-cfm capacity centrifugal fan is provided downstream of each SGTS filter train. This fan is a direct-drive type with a single-speed motor powered from Class 1E buses. The decay heat produced by the radioactive particles in the inactive charcoal filter train is removed by passing equipment room air through the inactive filter train. The air is then exhausted to the main stack by the fan of the active filter train. A missile-protected opening with a backdraft-type tornado damper located in the equipment room allows outside air to be induced into the room when makeup air for decay heat cooling is required.

The SGTS charcoal filter trains are located in the standby gas treatment building at el 261 ft.

Airtight access doors are provided to give complete accessibility to all components for servicing.

6.5.1.3 Design Evaluation

The SGTS is designed to preclude direct release of fission products from the reactor building to the environment during all modes of operation by the following features:

1. The SGTS is housed in a Category I structure. All surrounding equipment, components, and supports are designed to pertinent safety class and Category I requirements.

2. The SGTS consists of two 100-percent capacity, physically separated filter trains. Should any component in one train fail, filtration can be performed by the redundant train.

3. The SGTS component design and qualification testing are in accordance with the recommendations of RG 1.52 to the extent discussed in Section 1.8.

4. During LOOP, all active components such as motors, damper operators, controls, and instrumentation operate from their respective independent standby power supplies.

Should a LOCA occur during primary containment purge with the SGTS operating in the pressure control mode, the calculated accident doses are within the 10CFR50.67 criteria.

Should a LOCA occur while the SGTS is operating in the pressure control mode, the resultant pressure at the SGTS filter is below the design pressure of 1 psig. The following are considered in this analysis:

1. The inboard and outboard CPS isolation valves to the drywell (14 in) and wetwell (12 in) are fully open at time=0 when the LOCA occurs. These lines are tied together to a 20-in header.

2. The 20-in line is shut off from the SGTS filters via a safety-related fail close valve (2GTS*AOV101), and the 2-in bypass line is open via a safety-related fail close valve (2GTS*SOV102).

3. The CPS containment isolation valves close in 5 sec.

4. The LOCA pressure at t=5 sec is 26.6 psig.

5. For purposes of conservatism, the LOCA pressure of 26.6 psig is assumed to occur instantaneously at t=0 sec, the pressure control valve (2GTSPV104) in the 2-in bypass line is full open, and the resulting pressure spike at the SGTS filter occurs instantaneously.

The radiological consequences of this event are discussed in Section 15.6.5.

6.5.1.4 Tests and Inspection

The SGTS and its components are thoroughly tested in a program consisting of the following:

1. Manufacturer's qualification.

2. Preoperational tests.

3. Periodic surveillance tests.

The above tests are performed in accordance with the objectives of RG 1.52.

6.5.1.4.1 Preoperational Testing

The SGTS charcoal filter train housings are pressure tested for leakage in accordance with ANSI N510, Section 6. Leak rates shall be in accordance with the requirements of ANSI N509-1980, Section 4.12.

HEPA filters are shop tested prior to installation, in accordance with MIL-F-51068 and MIL-STD-282, at 100 percent and 20 percent of rated flow.

Impregnated activated carbon is tested before installation in accordance with the methods specified in RDT Standard MI6-IT. Tests determine apparent density, degree of activation, percent hardness, percent moisture, particle size distribution, and ash content. These tests meet the intent of RG 1.52. Elemental and methyl iodine removal and retention capabilities are measured (at postulated accident conditions) in accordance with RDT Standard MI6-IT. Impregnate content, leachout, and charcoal ignition temperature are also determined. HEPA filter banks are tested in place before operation to verify 99.97 percent retention based on the DOP smoke penetration test.

The charcoal filter banks are preoperationally leak tested using a gaseous halogenated hydrocarbon refrigerant to measure bypass leakage and element imperfection in accordance with ANSI N510, Section 12.

6.5.1.4.2 In-service Testing

In-service testing of the SGTS is conducted in accordance with the surveillance requirements given in the Technical Specifications and TRM Section 3.6.4.3.

6.5.1.5 Instrumentation Requirements

Description

Safety-related instruments and controls are provided for automatic and manual control of the SGTS. The controls and monitors described below are located in the main control room. The control logic is shown on Figure 6.5-1.

Operation

Both filter trains are started automatically when there is a LOCA or a reactor building refueling area exhaust vent duct low airflow or high radiation signal. Stopping one of the trains manually after automatic initiation will reset its start signal and place it in standby. The standby filter train will start automatically when a high filter charcoal temperature occurs in the operating filter train or when the indoor negative/outdoor atmospheric pressure differential falls below a predetermined setpoint, coincident with either a LOCA or high radiation signal. The filter trains can also be started manually.

A SGTS inlet valve from the reactor building ventilation system will open automatically when the associated filter train start signal is present and close when the signal is reset. The valves can also be opened and closed manually.

SGTS filter train inlet and fan discharge valves will open automatically when the associated filter train start signal is present and close when the signal is reset or when the filter train fan has failed to start after a preset time. The valves can also be opened and closed manually.

The SGTS filter train decay heat removal air inlet valves can be opened and closed manually.

A SGTS filter train fan will start automatically when its associated filter train start signal is present and stop when the signal is reset. The fans can also be started and stopped manually. Interlocks prevent a fan from running unless its discharge valve is open.

Negative pressure in the reactor building is automatically controlled by the SGTS filter train recirculation line pressure control valves. Differential pressure is set by manual/automatic stations. The valves can also be controlled manually. If problems arise in the filter bypass line, the line may be closed. This may result in a greater vacuum in the reactor building, but will not impact the GTS system's capability to perform its safety function. An interlock closes a valve when its fan is not running.

The primary containment purge exhaust and depressurization to SGTS isolation valves are opened and closed manually.

Monitoring

Indicators are provided for:

1. Reactor building differential pressure (redundant).
2. Each filter train inlet and outlet temperature.
3. SGTS exhaust radiation level (local microprocessor).

Recorders are provided for:

1. Each filter train flow and filter differential pressure.

Alarms are provided for each:

1. SGTS train inoperable.
2. SGTS train heater differential temperature low.
3. Reactor building positive differential pressure high.
4. Reactor building negative differential pressure low.
5. SGTS train trouble.
6. SGTS train airflow low.
7. SGTS fan auto trip/fail to start.
8. (SGTS effluent) radiation monitor trouble.
9. SGTS MOV motor overload.
10. SGTS fan motor overload.
11. Process airborne radiation (SGTS effluent) monitor activated.

6.5.1.6 Materials

The housings and all framing materials of the SGTS filter trains are fabricated of steel alloys and, as such, are nonflammable. The following is a list of the materials used in the various components of the SGTS filter trains:

1. Demisters The demister (moisture separator) section of each SGTS filter assembly is a Mine Safety Appliance Company (MSA) Model G separator consisting of wire mesh and fiberglass-coated wire mesh in series, separated by grid assemblies. The frame is 16-gauge Type 304 stainless steel. The demisters are designed and constructed to a manufacturer's standard design that has been qualified by testing in accordance with MSAR 71-45, and meet the Underwriters' Laboratories Inc. (UL) Class 1 requirements.

2. Heater An electric heating coil is provided upstream of the prefilters to reduce the relative humidity of the airstream to 70 percent (maximum). A heating element is integrally mounted in the filter train and connected to a terminal box. Heating elements are of the U-bent, finned tubular type with stainless steel sheaths and monel helical fins wound onto the sheaths. Heater enclosure frame and remote control panel are constructed of 14-gauge and 12-gauge Type 304 stainless steel, respectively. Heat baffles are of 16-gauge Type 304 stainless steel.

3. Prefilters Prefilters are of the high-efficiency, extended medium, dry type with pleated media and full depth rigid frames. The medium is MSA Dustfoe M-1000 and is stamped UL Class 1. The filter medium is fiberglass encased in a Type 304 stainless steel frame.

4. HEPA Filters There are two banks of HEPA filters, one before and one after the charcoal adsorber filters, on each SGTS filter train. The filters are MSA HEPA P/N 465062 and consist of waterproof fiberglass media in Type 304 stainless steel frame with aluminum separators.

5. Charcoal Adsorber Filters The charcoal adsorbent material is steam-activated coconut shell carbon MSA P/N 463563. The minimum ignition temperature is 594°F at 40 fpm face velocity. Each carbon adsorber module is fabricated from Type 304 stainless steel.

6. Piping, Piping Components, and Valves All nuclear safety-related piping is classified as ASME III, Code Class 2, and is designed, fabricated, installed, and inspected in accordance with ASME III. All nuclear safety-related piping components and valves are designed in accordance with the rules of Subsection NC, ASME III. All nonnuclear-safety piping, piping components, and valves are designed in accordance with ANSI B31.1.

   All safety-related valves and accumulator tanks associated with the GTS air supplies are designed and fabricated in accordance with the requirements of ASME III Class 3.

The SGTS is not exposed to accident environments of extreme temperature or radiation that could potentially produce pyrolytic or radiolytic decomposition of filter materials; thus filter train decomposition products are not present. A fire from external sources, which could cause pyrolytic decomposition of construction materials of the charcoal filters, is not postulated to occur simultaneously with any other plant accident requiring the operation of the SGTS for radioiodine removal credit.

6.5.2 Containment Spray System

The containment spray system is relied on to perform a fission product removal function following a DBA LOCA accompanied by significant fuel damage, in support of the AST methodology. The containment spray system design is described in Section 6.2.2.

6.5.3 Fission Product Control System

The SGTS is used to control the cleanup of fission products from the secondary containment following an accident and is described in detail in Section 6.5.1. Detailed descriptions of the primary and secondary containments are provided in Sections 6.2.1 and 6.2.3, respectively. A detailed description of the hydrogen recombiner system is provided in Section 6.2.5.

TABLE 6.5-1

DESIGN DATA OF PRINCIPAL EQUIPMENT
STANDBY GAS TREATMENT SYSTEM

<u>Filter Assembly</u>	
Equipment Mark No.	2GTS*FLT1A, 1B
Quantity	2 (100% capacity each)
Each assembly includes the following components:	
1. Moisture Separator:	
Type	Wire mesh
Media	Fiberglass coated wire mesh
2. Prefilter:	
Type	Disposable
Media	Fiberglass
Efficiency, ASHRAE Std. 52, %	78
3. Charcoal Adsorber:	
Type	Gasketless
Media	Charcoal
Retention, %	99
4. High-Efficiency Final Filter:	
Type	HEPA
Media	Fiberglass
Efficiency, NBS dustspot, %	99.97
5. Heating Coil:	
Type	Electric
Capacity, kW	20
<u>Exhaust Fan</u>	
Equipment Mark No.	2GTS*FN1A, 1B
Quantity	2 (100% capacity each)
Type	Centrifugal
Capacity, each, cfm	4,000
Static pressure, each, in W.G.	24.60
Motor, each, hp	40

6.6 INSERVICE INSPECTION OF SAFETY CLASS 2 AND 3 COMPONENTS

In compliance with the applicable portions of GDC 37, 40, 43, and 46, an inspection program was developed that includes preservice and periodic inservice inspections (ISI) of ASME Class 2 and 3 components. The preservice examinations were based on the ASME Boiler and Pressure Vessel Code, Section XI, 1980 Edition through the Winter 1980 Addenda, except for the ASME Class 2 piping in the RHR system, ECCS systems, and containment heat removal system. These examinations were based on ASME Section XI, 1974 Edition through Summer 1975 Addenda. All ASME Class 2 and 3 components that require inservice inspection or inservice testing, as required by 10CFR50.55a and specified by the applicable Code, are designed, fabricated, and erected with the objective of full compliance with the requirements of 10CFR50.55a. See Table 3.2-1 for systems or portions of systems which are nonsafety related but were designed, fabricated and erected to ASME Class 2 or 3 requirements (optionally upgraded) and are not inservice inspected to ASME Section XI.

6.6.1 Components Subject to Examination

ASME Class 2 and 3 components are classified in accordance with the criteria of RG 1.26. ASME Class 2 components will be inservice inspected in accordance with and to the extent required by ASME XI, Subsection IWC and Table IWC-2500-1 (except as noted in Table 3.2-1), per the requirements of 10CFR50.55a.

ASME Class 3 components will be inservice inspected in accordance with and to the extent required by ASME Section XI, Subsection IWD and Table IWD-2500-1 (except as noted in Table 3.2-1), per the requirements of 10CFR50.55a.

Refer to Section 3.9A.6 for a description of inservice testing (IST) of pumps and valves.

6.6.2 Accessibility

The design and arrangement of ASME Class 2 components provide access for ISI required by ASME Section XI, Subsection IWC. Wherever possible, adequate access is provided for performance of required volumetric and surface examinations specified in ASME Section XI, Table IWC-2500-1. ASME Class 2 welds that will receive ultrasonic examination are smoothed, contoured, and finished in order to permit an acceptable examination of the welds.

The design and arrangement of ASME Class 3 and exempt ASME Class 2 components provide for performance of all visual inspection techniques and surveys to meet the requirements of ASME Section XI, Subsection IWD, Table IWD-2500-1. Special design considerations are given to those systems that are intended to be examined during normal plant operation. In some cases, special access platforms and ladders are provided to expedite ISI activities where no other permanent access is available. Items that are not readily accessible will be identified in the ISI program.

6.6.3 Examination Techniques and Procedures

ISI examination techniques for ASME Class 2 systems and components are volumetric, surface, and visual, in accordance with the requirements of Table IWC-2500-1 of ASME Section XI. Ultrasonic techniques are generally employed where volumetric examination is required, and either liquid penetrant or magnetic particle techniques are employed where surface examination is required. Visual examinations are conducted in accordance with the requirements of ASME Section XI, Table IWC-2520-1 and Subsubarticle IWA-2210.

ASME Class 3 systems and components are given a visual examination during system inservice tests, component functional tests, or system pressure tests, in order to detect evidence of component leakage, structural distress, or corrosion, in accordance with the requirements of Table IWD-2500-1 and Subsubarticle IWA-2210 of ASME Section XI.

6.6.4 Inspection Intervals

For ASME Class 2 systems and components, an ISI schedule will be developed in accordance with ASME Section XI, Subarticle IWC-2400, and Table IWC-2500-1. The inspection schedule will be detailed in the ISI program. ISI for ASME Class 3 systems and components is conducted when systems are undergoing either a system inservice test, component functional test, or system pressure test as specified by ASME Section XI, Subarticle IWD-2400 and Table IWD-2500-1.

6.6.5 Examination Categories and Requirements

The ISI categories and requirements for ASME Class 2 systems and components are in agreement with and are designed to permit ISI required by ASME Section XI, Table IWC-2500-1.

ISI categories and requirements for ASME Class 3 systems and components are in agreement with and are designed to permit ISI required by ASME Section XI, Table IWD-2500-1.

6.6.6 Evaluation of Examination Results

Evaluation of preservice examination results of ASME Class 2 and 3 components will be in accordance with the evaluation criteria specified in ASME Section XI, Article IWB-3000. Repair procedures for ASME Class 2 components will comply with the repair rules of ASME Section XI, IWC-4000. Repair procedures for ASME Class 3 components will comply with the repair rules of ASME XI, IWD-4000.

6.6.7 System Pressure Tests

System pressure tests on ASME Class 2 systems and components will be conducted to comply with the criteria established in ASME Section XI, Article IWC-5000. System pressure tests on ASME Class 3 systems and components will be conducted to comply with the criteria established in ASME Section XI, Article IWD-5000.

6.6.8 Augmented Inservice Inspection to Protect Against Postulated Piping Failures

No augmented ISI will be required for ASME Class 2 and 3 systems and components since there is no ASME Class 2 or 3 high-energy piping between containment isolation valves. As indicated in Table 1.9-1, Note 12, Difference 3, B31.1 Class 2 and Class 3 piping exists between the containment isolation valve and the associated first restraint. During each inspection interval, as defined in IWA-2400, an ISI is performed on all nonexempt ASME Code, Section XI circumferential and longitudinal welds within the break exclusion region for B31.1 Class 2 and 3 high-energy fluid system piping. These inspections consist of augmented volumetric examinations (nominal pipe size greater than or equal to 4 in) and augmented surface examinations (nominal pipe size less than 4 in) such that 100 percent of the previously defined welds are inspected at each interval, or as required per the risk-informed process for piping outlined in EPRI Topical Report TR-1006937 and Nuclear Engineering Report NER-2A-025 NMP2 RI-ISI BER Evaluation. The break exclusion zone consists of those portions of high-energy fluid system piping between the moment limiting restraint(s) outboard of the outside primary containment isolation valve and the moment limiting restraint(s) beyond the inside primary containment isolation valve. The criteria that determine which restraint(s) are chosen to determine the limits of the break exclusion zone are based upon those restraints which are necessary to ensure the operability of the primary containment isolation valves.